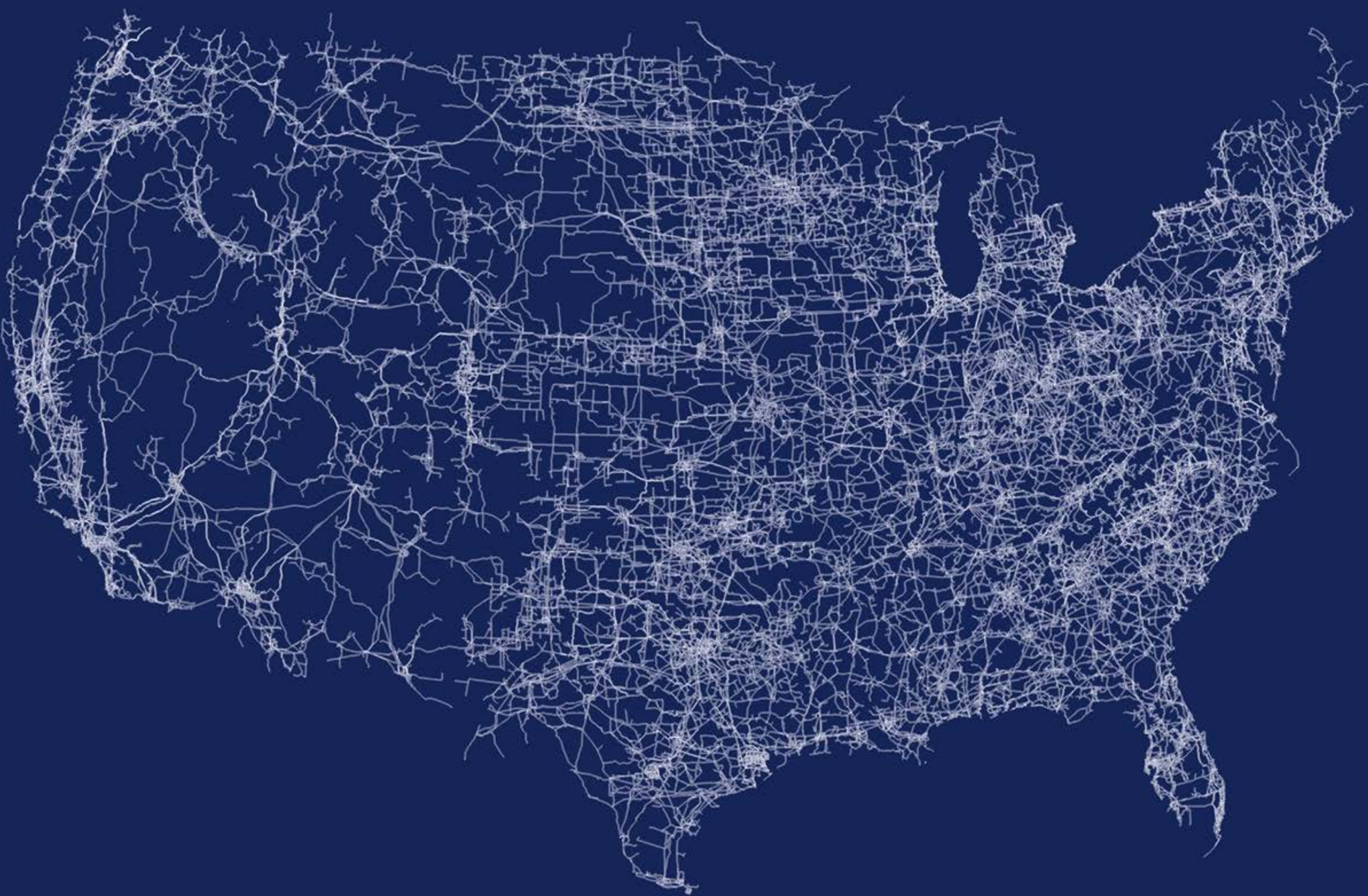

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Electricity Transmission System Research and Development: Grid Operations

Prepared for the
Transmission Reliability and Renewable Integration Program
Advanced Grid R&D, Office of Electricity
US Department of Energy

April 2021

Electricity Transmission System Research and Development:

Grid Operations

Transmission Innovation Symposium:
Modernizing the U.S. Electric Grid

2021 White Papers

Prepared for the
Office of Electricity
U.S. Department of Energy

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April 2021

The work described in this study has been authored by authors at Washington State University, under subcontract from Lawrence Berkeley National Laboratory No. 7548374, and Texas A&M University, under subcontract from Lawrence Berkeley National Laboratory No. 7547655, under the U.S. Department of Energy contract No. DE-AC02-05CH11231.

Acknowledgments

The work described in this study was funded by the Permitting, Siting and Analysis Division of the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

If this document is referenced, it should be cited as:

Bose, Anjan, and Overbye, Thomas J. 2021. Electricity Transmission System Research and Development: Grid Operations. In *Transmission Innovation Symposium: Modernizing the U.S. Electrical Grid,* U.S. Department of Energy.

Foreword

The foundation of the U.S. Department of Energy (DOE) Transmission Reliability research program was established 20 years ago through a series of commissioned white papers. The white papers reviewed the dramatic institutional and regulatory changes that the transmission grid was undergoing and articulated the technical challenges that those changes created. The challenges outlined in those white papers were used to formulate the initial research goals of the Transmission Reliability program. Today, 20 years later, many of the targets set out for the program have been accomplished. At the same time, the electricity grid is undergoing a dramatic shift with the addition of substantial renewable and distributed energy resources and heightened risks from phenomena such as severe weather. These shifts pose new challenges for the transmission grid, today and into the future. As a result, now is an appropriate time to step back and review the current technical challenges facing the industry and to identify the next set of targets for DOE's transmission-related research and development (R&D) programs within the Office of Electricity's Advanced Grid Research and Development Division.

To support this process, DOE, supported by Lawrence Berkeley National Laboratory (LBNL) and Pacific Northwest National Laboratory (PNNL), has commissioned small teams of experts drawn from the national laboratories and academia to prepare a new set of foundational white papers. Each white paper reviews and assesses the challenges now facing the U.S. transmission system from the perspective of the technologies that will be required to address these challenges. The focus of the white papers is on technical issues that must be addressed now to prepare the industry for the transmission system that will be required 10-20 years in the future. A key purpose of these papers is to identify technical areas in which DOE can take a leadership role to catalyze the transition to the future grid.

The five white papers are:

1. **U.S. Electricity Transmission System Research & Development: Grid Operations**
   Lead Authors: Anjan Bose, Washington State University, and Tom Overbye, Texas A&M University

2. **U.S. Electricity Transmission System Research & Development: Distribution Integrated with Transmission Operations**
   Lead Authors: Chen-Ching Liu, Virginia Polytechnic Institute and State University, and Emma Stewart, Lawrence Livermore National Laboratory

3. **U.S. Electricity Transmission System Research & Development: Automatic Control Systems**
   Lead Authors: Jeff Dagle, Pacific Northwest National Laboratory, and Dave Schoenwald, Sandia National Laboratories

4. **U.S. Electricity Transmission System Research & Development: Hardware and Components**
   Lead Authors: Christopher O'Reilley, Tom King, et al., Oak Ridge National Laboratory

5. **U.S. Electricity Transmission System Research & Development: Economic Analysis and Planning Tools**
   Lead Authors: Jessica Lau, National Renewable Energy Laboratory, and Ben Hobbs, Johns Hopkins University

The white papers will be vetted publicly at a DOE symposium in spring 2021. The *Transmission Innovations Symposium: Modernizing the U.S. Power Grid* will feature expert panels discussing each white paper. The symposium will also invite participation and comment from a broad spectrum of stakeholders to ensure that diverse perspectives on the white papers can be heard and discussed. Proceedings will be published as a record of the discussions at the symposium.

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Acronyms and Abbreviations

AC	alternating current
AGC	automatic generation control
BA	balancing authority
CA	contingency analysis
CEII	critical energy/electric infrastructure information
DC	direct current
DOE	United States Department of Energy
EMS	energy management system
ERCOT	Electric Reliability Council of Texas
FACTS	flexible alternating current transmission system
FERC	United States Federal Energy Regulatory Commission
FERC	Federal Energy Regulatory Commission
HILF	high-impact low-frequency
HVDC	high-voltage direct current
Hz	Hertz
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utilities
ISO	independent system operator
kV	kilovolt(s)
LMP	locational marginal price
MW	megawatt
NERC	North American Electric Reliability Corporation
NERC	North American Electric Reliability Corporation (originally National Reliability Council)
OPF	optimal power flow
OTS	operator training simulator
PJM	PJM Interconnection LLC (historically, Pennsylvania, Jersey, Maryland Power Pool)
PMU	phasor measurement unit
PV	photovoltaic
RAS	remedial action scheme
RC	reliability coordinator
RTCA	real-time contingency analysis
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
SE	state estimation
SPS	special protection scheme
SVC	static volt ampere reactive compensator
TOP	transmission operator
V	volt(s)
WECC	Western Electricity Coordinating Council

Executive Summary

This white paper addresses transmission grid operations, how they are evolving especially as more renewable and distributed resources are being added to the grid, and what research and development are needed to continue operating the power grid in a reliable, economic manner during the coming decades.

The paper starts with a brief history of the evolution of transmission operations from the early digital control centers to the present day, including some predictions about expected future evolution. Transmission grid operations are coordinated through supervisory control and data acquisition - energy management systems (SCADA-EMSs) that are usually housed at the overall reliability coordination level of the independent system operator/regional transmission operator, with several underlying control centers operating smaller regions of transmission. Tools that support real-time decision making collect measurements, process them, and display the results to the operator. As the number and rate of measurements increases, these tools need to be developed to improve operator situational awareness. Another set of engineering tools, such as state estimators and contingency analysis, provides suggestions to the operator based on real-time data. These tools need to be expanded to take advantage of the increase in available measurement data, such as from synchrophasors.

Control centers are the repositories of streaming real-time data and thus are very valuable libraries of information for off-line analysis that can be the basis for forecasts, studies of new evolving grid behaviors, and updates of the models used in analysis. These repositories can also be the training libraries for machine learning and artificial intelligence. This kind of analysis is closely related to transmission planning, which has become more difficult over time because of the uncertain nature of generation growth. Thus, this paper discusses transmission planning in some detail as well as the need for planning tools to deal with uncertainties regarding generation. Although construction of generation will remain deregulated, transmission planners will still have to calculate and track generation adequacy, which will also require new tools.

With increasing grid complexity, the skill set needed to operate the transmission system is expanding, and operator training is becoming more important. Improvements are needed in training simulators, which tend to be quite rudimentary compared to, for example, flight simulators. Recent weather incidents that have affected the grid—storms, cold snaps, fires—are pointing toward the need greater more focus on grid resilience. These kinds of high-impact, infrequent events need much more study with improved tools to understand preparedness as well as the costs of decisions about grid-hardening efforts.

The paper concludes with a discussion of the infrastructure needed for the types of research and development mentioned above. There is only one grid, which operates 24-7; research on improved operational tools requires realistic simulation of these transmission operations. We underscore the

need for real, synthetic data sets and models of every grid component along with compatibility of tools based on standardized data format and management.

1. Introduction

This paper focuses on transmission grid operations and is one in a series of five white papers that review and assess the challenges facing the U.S. transmission system during the next 10 to 20 years.

Historically, the primary purpose of the higher-voltage transmission system has been to move electrical energy from generators to the lower-voltage distribution system, which ultimately delivers the energy to end users. This dynamic is changing as more and more generation is located on the distribution system, often in the form of rooftop photovoltaic (PV) systems. Nevertheless, the transmission system continues to transfer the vast majority of the electrical energy used in this country, and, as noted in a [1], "For at least the next two decades, most customers will continue to depend on the functioning of the large-scale, interconnected, tightly organized, and hierarchically structured electric grid for resilient electric service." In North America this electrical energy is supplied by four large, interconnected, 60-Hertz (Hz), alternating current (AC) systems, the largest of which covers most of the eastern part of the continent. Each of these interconnections is, in essence, a single large electrical circuit throughout which disturbances can move at nearly the speed of light.

The main societal goals for electrical supply are: (1) safety and security, (2) affordability and equity, (3) sustainability and clean power, and (4) reliability and resiliency. A major driver today is the need to mitigate climate change by shifting from fossil fuel generation to green resources. These new green generation resources are more variable and more distributed on the grid than past generation has been and will require new transmission, distribution, and customer-side technologies. Apart from the research required for these new component technologies, more research and development on how to plan, design, control, and operate this newly evolving grid will also be needed. Although the transmission grid is only a portion of the end-to-end grid that also includes generation, distribution, and the load, transmission being impacted by the same drivers and societal goals that are affecting the evolution of the whole grid.

The specific focus of this paper is on how the transmission system is operated, primarily from the day-to-day perspective of a human operator. This paper does not cover:

(1) details of the operational seam between the transmission and distribution systems, which is the focus of paper 2 in this series, entitled *Distribution Integrated with Transmission Operations*; (2) the specific technologies used for automatic control, including much of the protection system, which are the focus of paper 3 in this series , entitled *Automatic Control Systems*; (3) transmission equipment itself, including monitoring systems, which is the topic of paper 4 in this series, entitled *Hardware and Components*; and (4) electricity markets and the economic aspects of longer-term planning, which are the focus of paper 5 in this series, entitled *Economic Analysis and Planning Tools*. Most of this paper focuses on the technologies used in transmission control centers where human operators are still very much in-the-loop. We also consider some engineering, non-economic issues associated with longer-term grid planning. Some overlaps with the other papers in the series are inevitable because human

operators and engineers are ultimately involved with all aspects of the transmission system during day-to-day operations. For example, when all generation was connected to the grid through transmission substations, generation control and operation were the sole responsibility of the transmission operator, but, with increasing amounts of generation on the distribution system, operations are now shared and need to be coordinated.

When the grid works correctly, as it does the vast majority of the time, it is, for most people, ubiquitous and unnoticed. It is also essential to the functioning of modern society. If the grid were to fail, the outcome could quickly become catastrophic. This was demonstrated by two major events in 2020-2021. The first event as a positive example of reliable grid functioning: the grid's performance at the beginning of the COVID 19 crisis. In the early days of the pandemic, when fear was widespread and store shelves emptied as many sheltered in place, the lights stayed on. That the grid worked as it was supposed to during this time was due in no small part to the dedication of the many individuals who keep our critical infrastructure running. The second example shows the impact of grid failure. In mid-February 2021, when parts of the central United States were experiencing near-record cold, the grid in Texas faltered and appears to have almost collapsed, with widespread and lasting effects on residents. Had the grid failed altogether, the results would most likely have been even more catastrophic. An overriding recommendation from this paper is that the most important research focus needs to be on preventing the impacts of these types of rare grid events to the greatest extent possible, and, when it is not possible to prevent failure, to mitigate the impacts as much as possible.

The remainder of this paper is organized as follows:

- Section 2 introduces the complexities associated with transmission grid operations by tracing their historical development leading up to the present day.
- Section 3 presents our view of how the electricity grid is likely to change during the next two decades, framing the discussion of the technological challenges that we believe need to be addressed.
- Sections 4 through 9 look at specific aspects of these technological challenges.
- Section 10 discusses issues that we believe are currently limiting the effectiveness of research on grid operations.
- Section 11 provides specific recommendations regarding research that the United States Department of Energy (DOE) should support.

2. Electricity Transmission Grid Operations: Past and Present

The overall focus of this white paper is on technologies to power future transmission grid operations. Given the complexities of transmission grid operations, some background is needed. We set the stage for the remainder of the paper by describing the historical evolution of grid operations.

The electricity grid got its start in the early 1880s based on a concept known as central station power. At that time, the grid utilized direct current (DC) and quite low operating voltages of about 100 volts (V). As its name implies, central station power entails a single generating station supplying a relatively small number of customers in a small geographic region. From an operations perspective, control of these first central stations was focused on the DC generators at the station. The grid itself required maintenance and planning but little operational control.

Within a decade of their inception, these local DC grids were increasingly competing with AC grids. A key advantage of AC grids came with the invention, in 1885, of the transformer, which allowed voltage to be easily increased by potentially many times but which only worked in AC systems. Because the electric power transferred in a wire is equal to the product of the voltage and wire's current, and the losses vary with the square of the current, the use of AC systems operating at increasingly higher voltages allowed for long-distance power transfer and thus for the creation of the first transmission systems. The three-phase AC system also allowed twice the power-transfer capability compared to an equivalent DC system. By 1915 there were AC lines with operating voltages of 130 kilovolts (kV) and transmission lines spanning hundreds of miles. Frequency standardization, initially at 25 or 60 Hz, and then mostly at 60 Hz by 1920, allowed for the interconnection of different electric utilities [2].

Interconnected electric grids have at least two important advantages. First, with more generators connected, the loss of any single generator, or even an entire generation station, results in less system impact. Second, the interconnection of more generators from multiple electric utilities and a larger, and likely more diverse, electrical load, allows for better system economics because all of the participants on an interconnection can potentially buy and sell electricity amongst themselves. Such transactions are implemented by each utility monitoring the flow on all the transmission lines that join it to another utility (known as tie lines) and then adjusting internal generation to keep the sum of the tie-line flows at the desired value.

However, the creation of these larger electrical interconnections required additional operational control. In an AC system the most important control variable is system frequency. Within a synchronous electricity grid, all the parts of the system share a common frequency, and system frequency increases if there is too much generation and decrease if there is too much load. Keeping the frequency at the specified value while customers were free to unilaterally vary their electrical loads required cooperation among all of the different utility operators on the first interconnected grids. The invention of the Warren clock in 1916 gave utilities the ability to maintain much more precise frequency and gave millions of consumers access to highly accurate time through the use of synchronous motor clocks.

Electric utilities first joined together into power pools to gain the benefits of economic dispatch of more generators. The first power pool formed in 1927 when three utilities in the Mid-Atlantic region joined together to form what would eventually be PJM (originally the Pennsylvania, Jersey, Maryland Power Pool). Texas utilities forming the Texas Interconnected System in 1941, and the New England Power Pool dates from 1971. Initially, power pool electricity transactions were handled by telephone.

During the middle of the 20th century, the various separate grids across North America gradually merged until, by the mid-1960s, the continent was mostly supplied by the four large synchronous interconnections that exist today: the Eastern Interconnection, covering most of the continent east of the Rockies; the Western Interconnection (now known as Western Electricity Coordinating Council [WECC]), covering the western portion of the continent; the Electric Reliability Council of Texas (ERCOT) supplying most of Texas; and the Quebec Interconnection. A key driver of the formation of these large interconnections was the introduction of tie line bias control that allowed many individual utilities (known as “operating areas” or as “areas”) to be interconnected and maintain a constant interconnection frequency. This was accomplished by each utility calculating its own area control error, which included two components. The first component was the utility’s megawatt (MW) interchange, consisting of the sum of its tie-line flows minus any scheduled interchange. The second was a frequency bias term that added a value to the area control error based upon the deviation of the system frequency from the scheduled value (usually 60 Hz) multiplied by an area-specific bias factor (β) (the present-day details on setting this value are given in [3]). This approach worked extremely well in keeping the frequency of each interconnection close to its scheduled value, usually with a difference of much less than 0.1 Hz.

During the 1950s and early 1960s transmission grid operations consisted mostly of utilizing analog and then eventually digital computers to control area control error and to perform economic automatic generation control (AGC) to ensure that electricity was being produced economically. During this time period utilities also started to use supervisory control and data acquisition (SCADA) systems to allow remote monitoring and control of equipment. A SCADA system at that time consisted of remote terminal units at a substation or generator plant that provided both monitoring and control, a master station usually located in the control room of a large generator facility, and a communication system joining them.

A watershed moment for the electricity industry in general, and in the development of technologies for transmission grid operations specifically, was the November 1965 Northeast blackout that included New York City and affected about 30 million people. The cause of the event was a relay failure. The blackout highlighted society’s growing dependence on electricity and revealed both that the grid could fail over a large region and that better transmission grid monitoring and control were needed. A consequence of this event was the establishment, in 1968, of the National Electric Reliability Council (NERC) to focus on promoting the reliability and adequacy of the electricity grid (in 2006 the name was changed to the North American Electric Reliability Corporation). During this time period the Eastern and

WECC systems were connected for several years [4].

An important transmission control center development at this time, driven in part by the 1965 Blackout and in part by rapid developments in digital computing, was the creation of what would become known as energy management systems (EMSs). The idea of an EMS is to provide comprehensive automatic and human-initiated control of electricity transmission and generation [5], [6]. Building upon or replacing the existing SCADA system, the EMS combined much of the existing AGC of the transmission system with what would become known as network analysis functions.

Network analysis functions were meant to enable grid operators to make improved near-real-time decisions about potential future control actions and to better optimize the grid taking into account transmission system constraints. An accurate model for the real-time state of the system was essential for this purpose; what would later become known as state estimation (SE) was initially described in 1970 [7]. The SE algorithm combined a static model of the transmission grid with a potentially large number of imperfect real-time measurements of bus voltage magnitudes, transmission line and transformer flows, loads and generator injections, and circuit breaker status information. Using a least-squares optimization process, the state estimator provided a best fit value for the bus voltage magnitudes and angles, which, in turn, allowed for the creation of a power-flow model that represented a best fit for the current grid operating point. Although relatively straightforward to describe, SE proved to be quite difficult to consistently implement. After 50 years it is still far from perfect, but it has been substantially improved.

Also developing in the 1960s and 70s was the paradigm, still valid today, of five principal grid operating states: normal, alert, emergency, *in extremis*, and restorative (three states were described in [5] and expanded to five states in [8]). Usually, the system is in the preventative (normal) state in which all electrical load is being met with adequate reserves and no limit violations. The alert state is entered when there are still no violations, but reserves are no longer adequate. During the emergency state, the limits are no longer satisfied but the system is still intact, and some preventative control is possible to restore operations to the alert or normal state. The *in extremis* state is when significant parts of the system have been lost, and extreme control is needed to retain what is left. The restorative state is when the immediate disturbance is past, and the system is in the process of reconnecting. An issue that will be addressed later in this white paper is the need to focus more research on helping transmission grid operations deal with emergency, *in extremis*, and restorative states.

Many of the developments in transmission grid operations since then have been to implement the vision laid out in [6] recognizing that the industry itself was changing. When a valid SE solution became available, it could be used for a variety of network analysis functions to help operators and real-time support engineers operate and optimize the electric grid. One such function is contingency analysis (CA), in which power flow is repeatedly solved on the current operating state to see whether any statistically likely events (contingencies), such as the loss of a transmission line or generator, would cause limit violations. The concept of N-1 security required that all single-device contingencies be considered. The number of contingencies could be relatively large, so, when CA was originally introduced in the late 1970s, computational restrictions required that the list of contingencies be screened to identify those most likely to cause problems [9]. At this same time, economic dispatch algorithms were being combined with power flow for real-time optimizations that included transmission constraints; this was known as optimal power flow (OPF) [10] and was followed by another version, known as security-constrained OPF [11]. By the early 1990s, many electric utilities had EMSs that encompassed these network analysis capabilities.

At the same time, several technologies were developed that have had significant impact on transmission grid operations. First, with the growing complexity of the grid, improved training environments were needed, which led to the creation of operator training simulators (OTSs) or dispatcher training simulators [12], [13]. OTSs could provide interactive electricity grid simulations incorporating longer power-system dynamics than had been considered in the past, with a uniform frequency transmission grid model. These were used primarily for training grid operators. Second, with the vast increase in the number of system sensors and on-line analysis capabilities, improved techniques were needed to help operators and engineers maintain situational awareness, a term that would enter the power system lexicon in the early 2000s. The result was increased research on electricity grid visualization, with much of this work occurring at universities using the rapidly developing capabilities of personal computers [14], [15]. Third, with civilian use of the precise time signals provided by the global positioning system in the 1980s, it became possible to precisely measure the phase-angle differences between different voltage and current waveforms in large-scale electricity grids. This led to the development of phasor measurement units (PMUs) [16], [17] that measured both the magnitude and phase angles of the three-phase voltage and current waveforms. Fourth, with better optimization techniques and real-time power system information available from SE, a concept developed that later became known as locational marginal pricing [18]. The idea with this approach is that the incremental cost to supply electricity to each bus in the system, known as the locational marginal price (LMP), could be calculated. The LMP would be key in the development of real-time electricity markets during the 1990s.

During the 1990s and beyond, structural changes in the electric utility sector had major impacts on transmission system operations that continue today. Prior the 1990s, most of the grid was structured as vertically integrated monopolies in which individual utilities provided all electricity services within their territories. That is, they owned, controlled, planned, and operated essentially all of the generation and all of the transmission and distribution system. They were also the sole electricity suppliers to essentially all the customers (known as ratepayers) in their service territories. From a transmission operations perspective, each utility operated its own EMS, and interactions with neighbors were limited to joint planning (known as integrated resource planning) and possibly participation in a common power pool (such as PJM).

However, vertical integration changed dramatically during the 1990s, leading to fundamental changes in transmission system operation. Key drivers of the changes were substantial regional differences in the price of electricity and a societal desire to both provide customers with choice in their electricity suppliers and to allow for greater competition in electricity supply. Regulations enacted during that decade required that utilities provide non-discriminatory access to the interstate transmission system for all buyers and sellers in the bulk electricity market. In essence, this required that utilities treat their own generators the same way they treated third-party generators, and that communications between employees involved in transmission system operation and those involved in marketing be restricted in regard to non-public information about the operation of the transmission system.

Associated with these changes was the voluntary creation of independent system operators (ISOs) and regional transmission organizations (RTOs). ISOs were formed in response to U.S. Federal Energy Regulatory Commission (FERC) Order No. 888 (in 1997), and RTOs were formed in response to FERC Order No. 2000 to help coordinate the interstate transmission of electricity. There are some differences between RTOs and ISOs, with an RTO having more functionality and requiring a petition to FERC for approval, but the two types of organizations are quite similar (to add to the confusion, many entities that are RTOs actually use “ISO” in their names). The four characteristics of an RTO are 1) independence from electricity market participants, 2) a sufficiently large regional footprint, 3) operational authority to control the transmission facilities within its footprint, and 4) authority to ensure that the region meets NERC-mandated short-term reliability standards. Figure 1 [19] shows a map of the current North American RTOs, which cover about two-thirds of the country. Starting with PJM in 1997, most RTOs have gradually set up LMP-based electricity markets. For the rest of the country, more traditional wholesale electricity markets exist with the many utilities still vertically integrated and power transfers done primarily through bi-lateral transactions.

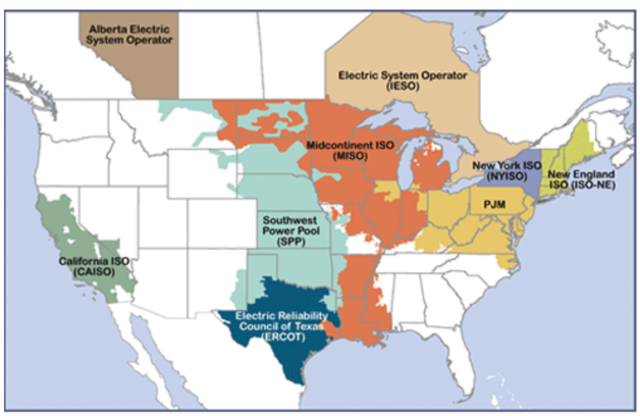

Figure 1: U.S. electric power markets

Between 1996 and 2003, four major events occurred that ultimately had important impacts on transmission system operations. First, during the summer of 1996, widespread cascading outages occurred in the WECC system, including oscillations and fragmentation of the system into a number of different electrical islands. These events highlighted the need for better models of the electricity grid’s dynamic response and showed the value of the limited number of PMUs that were installed at that time, which by 1996 had sample rates of 30 times per second. Second, the California electricity crisis in 2000-2001 demonstrated that the electricity markets that were new at that time could be manipulated, causing prices to skyrocket. Third, the events of September 11, 2001 highlighted the need for improved physical and cyber security and led to much of the electricity grid being classified as critical energy/electric infrastructure (CEII), greatly restricting the availability of information about the grid. Also, as noted in [20], after the events of September 11, 2001, the term "security" in a power system context was reserved for topics related to acts of terrorism and sabotage whereas "reliability" would be used to refer to maintaining grid operating conditions. Fourth, the August 14, 2003 Blackout [21], which affected more than 50 million people in the northeastern United States and Ontario, demonstrated that cascading outages could occur even with fairly sophisticated EMSs in use. Human factors, including a lack of situational awareness, factored heavily into two of the four causes of that event.

A consequence of these events for transmission operations was the passage of the Energy Policy Act of 2005 and NERC taking on a new role as the Electric Reliability Organization with the authority to require compliance with evolving NERC Reliability Standards. This change resulted in increased responsibility and authority for NERC reliability coordinators (RCs, which had been known before 2001 as "security coordinators"). As noted in NERC IRO-001.1.1, "Reliability Coordinators must have the authority, plans and agreements in place to immediately direct reliability entities within the Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state." Figure 2 [22] shows a map of current RCs. When we compare Figures 1 and 2, it is clear that most RTOs are also the RCs for their respective areas.

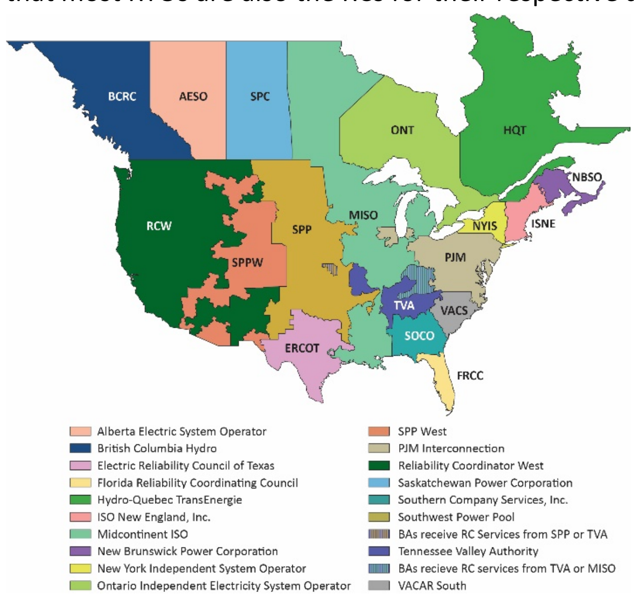

Figure 2: NERC reliability coordinators, December 2019

During the past 15 years, key changes in transmission operations have mostly been driven by changes in technology and by public concerns about environmental issues. During this time period, the U.S.'s sources of electrical energy have changed significantly, with coal's share dropping from 50% to 20%, natural gas increasing from 20% to 40% (driven by low prices related to fracking and lower carbon dioxide emissions compared to coal), nuclear and hydro holding steady at 20% and 7% respectively, and wind and solar growing from essentially zero to now 8% and 3% respectively. In particular regions, the changes have been more dramatic, with ERCOT at times getting more the half its electricity from wind.

Because wind and solar can be quite intermittent, transmission operations have had to adapt, and quite sophisticated systems are now used in some areas to estimate future wind and solar availability. A rapidly growing percentage of generation, including rooftop solar PV, is now also embedded in the lower-voltage distribution system and is referred to collectively as distributed energy resources.

The advent of the smart grid has enabled greatly increased monitoring, and to some extent control, on the transmission and distribution systems. The number of PMUs on the transmission system has risen during the past 15 years from just a handful to many thousands, each able to measure grid voltages and currents at rates of 30 Hz or higher. Better communication and computational systems along with growing use of big-data infrastructure have allowed RTOs and RCs to provide effective control over quite large areas. This has substantially reduced the number of control areas (now called balancing authorities [BAs]) in some parts of the country. Figure 3 [23] shows the current BAs (the circle representing each is sized proportionally to represent the BA's total load). The figure shows that consolidation of control areas not been uniform.

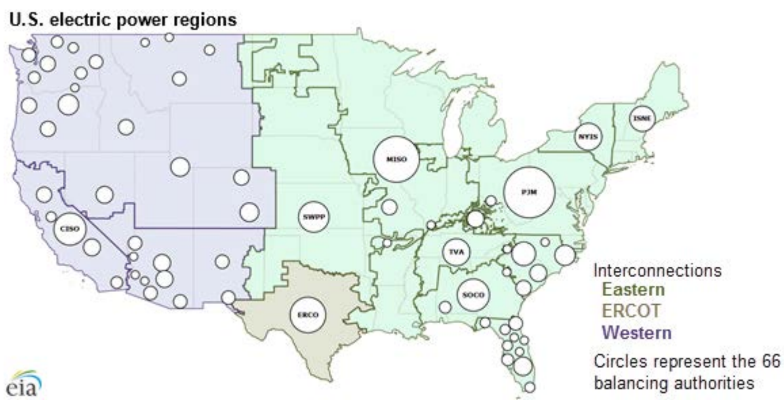

Figure 3: U.S. balancing authority areas in 2016

Next, we briefly describe the current technologies for direct control of the transmission system. In general, transmission grid power flows are controlled indirectly, primarily by changing the generation source, to maintain an interconnection's steady-state operation which requires that total generation match total load plus losses. From a grid perspective, load has mostly been seen as uncontrollable, with customers unilaterally deciding how much and when to consume. However, since the 1970s, utilities have exerted some direct load control. This trend accelerated with the advent of LMP markets, which increasingly allow for price-responsive load.

The key flow and voltage controls on the transmission system are (1) circuit breakers, (2) load tap changing transformers, (3) phase-shifting transformers, (4) switched shunts, (5) series capacitors, (6) flexible ac transmission system (FACTS) devices, and (7) high-voltage DC (HVDC) lines. Circuit breakers are binary (either closed or open), allowing for flow to be interrupted. They are widely used, particularly for grid protection to clear faults, for maintenance, and sometimes operationally to reconfigure the system. Load tap changing transformers and switched shunts are widespread and used primarily for voltage control. Although some are automatically controlled, many are manually controlled by a transmission system operator. Series capacitors are used to alter the impedance on long, high-voltage transmission lines. There are several hundred series capacitors in the North American grid with many in the WECC; they are commonly controlled manually. Phase shifters are transformers in which the phase angle across the transformer can be varied, allowing for direct control of the power flowing through the device. There are slightly more than one hundred phase shifters in North America. Most are manually controlled by the transmission operator. Control of circuit breakers, load tap changers, switched shunts, phase shifters, and series capacitors requires mechanical switching; that is, these are discrete controls that limit the number of times they can be switched. FACTS devices are static power electronics devices that are installed on the transmission system to provide continuous control of a system parameter. The most common FACTS devices are static var compensators (SVCs), which are power-electronics-controlled shunt devices that can provide continuously varying reactive power (within limits). They are usually set to automatically control a bus voltage magnitude. SVCs are quite common. Series FACTS devices use power electronics to provide continuous control of a series capacitor or reactor in a high-voltage transmission line; however, they are not common.

A key takeaway from this brief historical background is that the electricity grid, including the technologies for transmission operations, has been in a constant state of change for the past 140 years. We expect that change to continue. Transmission grid operations in 2021 can perhaps be summarized in with four words: *impressive, diverse, potentially opaque,* and *vital.*

What is currently taking place in control rooms associated with NERC RCs and RTOs is, to a large extent, a realization and significant extension of a vision that was presented more than 50 years ago in [5] and entails an *impressive* array of rapid measurements, communication, and analysis. SCADA and increasing numbers of PMUs provide raw input data from potentially hundreds of thousands of measurement points. It is common to obtain SE solutions every minute for network models containing hundreds of thousands of measurements and tens of thousands of buses with convergence much more than 98 percent of the time [24]. When SE is completed, real-time contingency analysis (RTCA) is performed, simulating the impact of thousands of potentially quite involved contingencies. AGC is run every few seconds, sending regulation signals to potentially thousands of generators. Many other applications are used, coupled with often hundreds of displays to help provide real-time operators and engineers with situational awareness about current and likely future conditions. In many RTOs, market applications also provide near-real-time LMP values every few minutes for various grid locations to help market participants make real-time decisions.

The second word is "*diverse*" or perhaps "*complex*." Almost from its inception, the electricity grid in this country has incorporated different generation resources and different ownership models, including investor-owned utilities, municipal utilities, electric coops, and various federal agencies and corporations (such as the Bonneville Power Administration, Western Area Power Administration, and Tennessee Valley Authority). Despite diversity of generation and ownership model, the structure of a single vertically integrated utility was for a long time a constant, with each utility unilaterally controlling its portion of the grid. This has now changed substantially but to varying extents across the country. For example, although RCs have authority to control the grid, they do not own the equipment and do not actually perform the control actions, which are carried out by the transmission operator (TOP), an entity that may or may not be the same as the transmission owner and the transmission planner. On the generation side, there are the operators who actually control the generation, and generator owners. This division of responsibilities could make it hard to implement control, especially during times of *in extremis* operation. Also, an increasing volume of generation is sitting behind the meter, usually under the control of the customer, and, in the case of large amounts of solar PV, not directly controlled. Although there is some commonality, each RTO has its own procedures, dictated by the sometimes quite unique situations of its members. All of this takes place along with increasingly complex electricity markets (more details provided in companion paper 5, *Economic Analysis and Planning Tools)*. Many in the industry have a good understanding of their portions of the grid, but few truly understand the breadth of U.S. transmission operations.

The third word that describes the transmission grid is potentially *opaque*, at least from the perspective of researchers. Information about the operation of the electricity grid is somewhat freely and widely shared among those with real-time operational responsibilities. This exchange is appropriate, needed, and not necessarily opaque. However, the events in Texas in February, 2021 may have revealed a potential breakdown in the sharing of crucial operational information about the ability of generators and their associated fuel supplies to deal with unusual but not record-setting cold. How much of this failure was due to designed opaqueness is not yet known. From the perspective of a researcher outside of the operations community, much of the information about the operation of the actual transmission grid is restricted or otherwise not easily available. This opaqueness is by design – either required or desired by transmission and generator owners and operators. CEII and market sensitivity impose some requirements for keeping information confidential. Some information that could legally be revealed is kept private as a result of non-disclosure agreements for which there might not be valid reasons, such as cost, potential future liability, or business privacy. Even with these limitations, there is much information that could be provided and that would be quite beneficial for the research agenda recommended in this paper. This topic is considered later in Section 10, Research Infrastructure, including potential remedies.

The last word to describe the grid is *vital*. Overall, the North American electricity grid operates extremely well, a testament to the skill and dedication of the hundreds of thousands of people responsible for its design and functioning. Prior to 2021, the last major, non-weather-related blackout was the Southwest Blackout of 2011 [25], and, prior to that, the blackout in 2003. This history reflects a high degree of overall reliability. As a result of this reliability, our society has become increasingly dependent on the electricity grid, and the grid is now appropriately deemed vital. A prolonged, wide-scale blackout, something that it appears Texas narrowly averted in February 2021, would be catastrophic. In regard to operating paradigms [8], existing transmission technologies seem to be working well in the preventative, alert, and, to some extent, emergency and restorative states. This is due to a combination of major advances in transmission operations technologies and the repetitive nature of grid operations. That is, although each day and each weather event is unique, there is a lot of commonality among them, and the industry has accumulated a lot of operational experience with the existing grid. However, there are two areas that we believe we should be the focus of significant research. First, there are a number of potentially quite high-impact events that should be cause for concern; [1] describes many of these events. The experience of COVID-19, although it has not had a unique impact on the electricity grid, has underscored the potential for a pandemic to have a severe impact. A loss of the electricity grid during this pandemic, particularly during its early stages, could have been catastrophic. Second, with the rapid integration of renewables, the grid itself is changing, and we may find ourselves in situations for which we do not have much prior operational experience. Therefore, special consideration is needed for dealing with the *in extremis* operating state when significant parts of the system have been lost, extreme control is needed to retain what is left, and the control center EMS might not be functioning correctly.

The electricity grid has come a long way in its 140 years of existence, and the future could be quite bright. The next section lays out potential future changes, and then the remainder of the document focuses on individual technologies and research recommendations for transmission operations.

3. Likely Future Scenarios

It is important to consider how the grid is likely to change in the next two decades as a basis for our discussion and recommendations regarding future research on transmission grid operations technologies. The future is inherently uncertain, and, as noted in [26], it is important to recognize that the future is unlikely to simply be an extrapolated view of the present. Therefore, researchers need to prepare for a range of scenarios and focus on work that can (as stated in [26]), "future-proof the grid so that regardless of how the grid evolves the United States is prepared." Research itself can help invent the future.

This section lays out some likely bounds around how the electricity grid might evolve during the next 20 years, and the following sections of the paper describe specific research directions to address these changes. An important caveat is that if we dismiss a technology, that does not imply that it should not be an area for research; it simply means that we see that technology as unlikely to significantly affect the transmission grid operations during the time period that is the focus of this paper, which is the next two decades.

During the coming 20 years, generation sources are likely to continue to transition to wind and solar PV along with some continued growth in natural gas. Some large companies and states are promising 100% renewable energy either within the 20-year horizon of this paper or soon after. For example, Google currently says it gets 100% of its electricity from renewable sources; and California, Hawaii, New Mexico, and Washington are promising to reach 100% carbon free by 2045. There will likely be continued retirements of coal plants and loss of some nuclear plants as their licenses expire. There are unlikely to be any other significant new generation sources (such as wave, tidal, or fusion) during the next 20 years.

Less certain is how much of the new generation will be small-scale PV in the distribution system versus utility-scale solar connected to the transmission system (currently one-third of PV is small scale). Wind will continue to be almost exclusively utility scale, with perhaps some growth in off-shore wind. Noting that wind and solar do not inherently provide inertia to the grid, there is a strong likelihood that total system inertia will continue to decrease, potentially causing frequency regulation challenges. However, some of this could be offset by what had been called synthetic inertia or more recently fast frequency response [27]. An open research issue is the detailed modeling required to represent the many distributed devices in transmission system operations. From a transmission operations perspective, there could be continued challenges from the intermittency of wind and solar as well as the predictable but operationally challenging phenomenon of a large influx of solar into some systems in the morning with the rising sun, and the vanishing of that energy when the sun sets.

Scenarios regarding net system load range from a gradual decrease, particularly with more solar PV located behind the meter, to a substantial increase if there is a rapid increase in the electrification of transportation. Given that for the country as a whole about 28 quads of energy is currently used in the transportation sector (with the vast majority coming from fossil fuels), compared to 37 quads for the electricity sector, the increase in electrical load from vehicles could be quite significant. For other loads there will likely be a combination of some increase because of economic and population growth and some decrease because of continued energy-efficiency improvements. Also, larger entities (companies, universities, the military) could exert significant influence over how they obtain their electricity, such as self-generation, microgrids, pledges of 100% renewables, etc.

The transmission grid itself (i.e., the wires) is unlikely to see any significant technology changes that would affect operations (the components themselves are the focus of another paper in this series, entitled *Hardware and Components)*. It is important to realize that the existing grid is already quite efficient in moving electricity over relatively long distances with perhaps 2 to 3% total transmission losses in the East and ERCOT, and 4 to 5% in WECC. New wire technologies, such as high-temperature superconducting cables and high-temperature, low-sag conductors, are likely to continue to fill niche applications. We also expect the highest AC transmission voltages to remain at 765 kV even though China is building a 1,000-kV grid. Solid-state transformers could play a role in the distribution system but are unlikely to be deployed at transmission-level voltages. The presence of existing technologies, such as HVDC and some FACTs devices (e.g., SVCs), could continue grow, providing increased flexibility in transmission system control.

It quite likely that the transmission system of the future will have access to potentially quite large amounts of storage, both larger-scale installations directly connected to the transmission system and others embedded in the distribution system, which could have a significant impact on transmission operations. Some storage might also be available from electric vehicles (known as vehicle-to-grid). Existing pumped-storage hydro is unlikely to be substantially expanded.

The essence of the grid is unlikely to fundamentally change. We expect the grid to continue to be operated to maintain a nearly constant frequency using the current tie-line bias control approach, albeit with a potential continual decrease in the number of BAs. How many new transmission lines will be added is uncertain, with scenarios ranging from little new construction to the creation of an extensive high-voltage (possibly HVDC) overlay, particularly in the middle of the country where there are substantial wind resources. With increased reliance on wind and solar, it is important to realize that 1) some parts of the country have very little available wind, and 2) in parts of the country during some times of the year (primarily winter) it is not unusual for large regions to see very little sun for long periods. If there is really a nationwide commitment to much larger amounts of renewable generation, the transmission grid will likely need to be expanded, perhaps substantially, to meet the new transportation requirements. During normal operations, the number of interconnections is unlikely to increase, and might even decrease as a result of joining the Eastern Interconnection with WECC. However, during system emergencies, the grid could be configured to break into a potentially large number of isolated systems through a process known as intentional islanding.

The two trends identified in [26] of a growth in grid observability and controllability are likely to continue. PMUs are now commonly deployed on the transmission grid, with some on the distribution system; it is quite likely that within the next few years PMUs will become even more ubiquitous. Enhanced communication and computation will allow for PMU information to be used both locally (e.g., at the substation) and more globally. As wireless service providers begin to deploy 5G networks, much faster and higher-bandwidth communication could be possible throughout the electricity grid. Data-sharing among RCs is likely to increase as well. The enhanced communication is likely to make other measurements more broadly available, such as from substation equipment (e.g., relays, digital fault recorders) and load. However, it is also important to consider that transmission grid operations would need to continue even during times of widespread communication failure, so such scenarios need to be considered.

The ability to adaptively control the transmission system is likely to increase as well. Power-electronics-based control is likely to increase, particularly in the distribution system, which has the potential to increase the controllability of load and distribution system DER. Some of this control will be local (e.g., a device sensing its terminal voltage magnitude and frequency), but much could be at either the substation or EMS level. Traditionally, most of the parameters associated with the operation of the protection and generator control systems have not been available as operations controls. This could change. Over the past several decades there has been a growing increase in the use of what are known as either remedial action schemes (RASs) or special protection schemes (SPSs). An RAS or SPS is defined by NERC as, "A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar [mega volt ampere reactive]), tripping load, or reconfiguring a system(s)" [28]. RASs are likely to increase both in number and sophistication. There could also be a blurring of the different operating states originally presented in [5] and [8] as the grid becomes more adaptively controlled.

Society's dependence on reliable electricity supply is likely to continue to increase along with the coupling between electricity and other infrastructure. For example, as noted earlier, it is quite likely that transportation will be substantially electrified, providing potential benefits of lower cost, lower emissions, and lots of additional energy storage. However, a detriment could be that a blackout could substantially impact transportation because electric vehicles could not be charged during an outage.

To future-proof the grid, it is crucial to do the research needed to address events whose impact on the grid and society could be catastrophic. Examples of these high-Impact, low-frequency (HILF) events ([29], with additional coverage in [30] and [1]) include physical and/or cyber attacks, geomagnetic disturbances, high-altitude electromagnetic pulses, and pandemics (even more severe than COVID). Although the specific likelihood of each of these events is unknown, the grid needs to be prepared. More severe instances of more common events, such as earthquakes, hurricanes, ice storms, tornados and volcanic eruptions, also need to be considered. The COVID-19 epidemic and the near collapse of the Texas grid in 2021 demonstrate that these less-frequent events do occur and can have devastating consequences.

The possibility that the operational structure of the transmission grid could change also needs to be considered. There is a reasonable likelihood that regions of the country without RTOs would get them, and some existing RTOs could merge. As technology improves, the number of RCs could also be reduced, with the limiting cases being a single RC for each interconnection or (less likely) for all of North America.

Almost certainly the size of the electricity grid models analyzed in EMSs will increase as more measurements increase observability. The number and complexity of the contingencies that are considered will also likely increase. New correlations will need to be considered when designing contingencies, such as the possibility of losing large amounts of renewable generation when there is a sudden change in the input of wind or solar. There will be a need for more probabilistic and risk-based considerations in the design of many transmission operations tools, including CA.

In summary, as has been the case for its 140 years of existence so far, the electricity grid and its associated control infrastructure will need to continue to evolve to meet the challenges of an uncertain future. Clearly, many transmission grid operations technologies will need to change. In the remainder of this paper, we describe specific areas of focus for research to ensure that, no matter what the future brings, the electricity grid and the nation are prepared.

4. Technologies to Support Operators' Management of Real-Time Operations

Transmission grid operations are managed through control centers where staff initiate supervisory control based on real-time data from the EMS. There are two main types of control centers – those operated by ISOs/RTOs/RCs, and those operated by TOPs – and two main types of technical staff – operators and real-time support engineers.

At control centers operated by ISOs/RTOs/RCs, the primary tasks are to oversee a large portion of the grid and often to also independently run the electricity market. These centers have the authority to control transmission operations but don't carry out the actual control actions. The portion of the grid covered by each RC varies, but all are large, and all have high-level EMSs. A large interconnection like the Eastern Interconnection has ten RCs in the United States that can exchange data with each other to operate the interconnection. Each RC has one main control center that supervises several others that take care of smaller regional transmission systems; both the main control center and the control centers covering small areas have EMSs. Thus, interconnection operations are managed cooperatively at the RC level, with each RC managing its own area by supervising a group of control centers that manage regions of the RC's area.

Control centers run by TOPs (who are often, but not always, the same as the transmission owners), vary from being extremely large and sophisticated (such as the Bonneville Power Administration) to quite small (such as a municipal entity or coop) with limited data infrastructure beyond a SCADA system.

The two main classes of technical staff that are directly involved in control center operations are operators and real-time support engineers. Operators actually run the system and must be NERC certified. In some locations the operators (sometimes known as RCs) have bachelor's degrees in electrical engineering; at other locations, they might not be engineers but would have a combination of training and extensive electricity grid experience. Providing direct support to the operators in the larger control centers are real-time support engineers who may also be involved in market functions. The operational functions in each control center can be divided into those that are taken care of manually by operators and those that are carried out automatically by computers. The control-center EMS supports both types of functions.

Before delving into the details of technologies needed to support real-time operations, it is important to note that successful transmission grid operation is the result of good decisions over a continuum of time frames ranging from long-range system planning to day- (or days-) ahead forecasting to in the moment (real time). Different organizations have different cutoff times designating when planning ends and operations begins. However, a reasonable time frame is a day ahead, for which a fairly accurate load forecast is needed to make unit commitment decisions. With the rapid growth of renewable generation, there is a need for tools to produce improved wind and solar forecasts. Because of the strong daily, weekly, and seasonal cycles in many of the inputs to these forecasts, improved machine learning algorithms could be particularly useful. Improved unit commitment algorithms could be helpful as well although as the grid moves away from large amounts of fossil-fueled generation with long start-up and shut-down constraints, this need may decrease.

A major part of the operators' responsibility at both the RC and TOP control centers is to monitor the system in real time. If the transmission system strays from the normal state to any of the other states mentioned previously (alert, emergency, *in extremis*, restoration), operators may have to take supervisory control action. Another important part of their jobs, particularly at the TOP level, is to coordinate the transmission switching that is associated with routine maintenance. The SCADA portion of the EMS supports manual monitoring and control. The SCADA system displays data that are gathered over communication lines from substations and performs routine functions such as limit checking and alarming. These measurement data include not just the analog information (voltage magnitudes, real and reactive power flow) but also breaker status. The scan rate for these data is usually on the order of a few seconds. Although today's communication and computers can handle much more frequent scan rates, the tradition of 2- to 10-second scan rates has persisted since the early days of SCADA systems in the 1960s. This has created a mismatch between SCADA data and PMU data, for which the scan rates are 30-60 times a second (17-33 milliseconds). That is, the scan rates for PMU data are two magnitudes faster than those for SCADA data. For this reason, PMU data are handled very differently when gathered at the substation and communicated to / stored in the EMS. This difference in data has created some impediments in designing the new applications that are made feasible by PMU data, especially if such applications need both PMU and SCADA data.

In addition to the measured data gathered at the substations, data are also obtained from many other sources. Similar types of SCADA/PMU data are exchanged among many EMSs that could be at the same level (in the systems of neighboring transmission owners) or hierarchical (an ISO/RTO that covers a large area communicating with transmission owner EMSs from each of its regions). The protocol for data exchange is the Inter-Control Center Communications Protocol, which has been used to exchange SCADA data for many decades but seems to have high latency for handling PMU data exchanges.

In addition to SCADA/PMU data and the processed version of these data (such as limit checks and alarms) that are presented to the human operator, the control-center computers can also conduct sophisticated analytics to provide the operator with information to support decision making. Two common analytics in use today are the previously mentioned SE and CA. SE can filter the noise on the actual measured values and can also provide a mathematical model of the real-time condition of the transmission network. If, in the process of monitoring the real-time SCADA data, the operator has doubts about some measurements, the state-estimated values are a valuable back-up. More important, the real-time network model allows the EMS to run through the scenarios of potentially thousands of contingencies and alert the operator to contingencies that may cause abnormal operating conditions. With more and better measurements, the number of these types of analytics designed to support the operator are expected to increase. For example, PMU data are already being used to detect sustained oscillations in the power system, and PMU-based state estimators have been shown to provide accurate state estimates many times per second [39].

The control center EMS also runs a power-balancing function, using the tie-line biased AGC. There are approximately 60 EMSs in the United States that perform this balancing and are designated BAs, keeping generation and load in balance, using system frequency as the control variable. This is an automatic function that does not require operator attention, but, because this function exchanges generation between neighboring BAs, the operator has to monitor these movements. A similar function encompasses voltage control of transmission substations and reactive power management, which, in the United States, is partially achieved through local control of reactive sources and transformers in the substations, partially by operator control at the TOP level, and partially at the RC level. Clearly this task requires good coordination. The operator also has to keep track of these voltages. The need for the control center to automatically control bus voltages is going to grow, and the control-center EMS will be expected to balance the reactive power as the BAs are already doing with real power. (In Europe and China, such wide-area control of voltage is already common.)

Another example of extensive local control is the protection system that employs thousands of relays, all of which are located in substations. These operate as needed, without any intervention of the operator, but, whenever any relays operate, the resulting change in grid topology must be noted by the operator and taken into consideration in relation to any subsequent manual operation. In recent years more intelligent wide-area protection schemes are being deployed that can detect more complex system conditions that require very rapid protective action. Such SPSs are increasing in number, and some are activated and de-activated manually by the operator under certain system conditions. These SPSs are also augmented with more adaptive relaying. Although the specific details of this real-time control are a focus of a companion paper, entitled *Automatic Control Systems*, for purposes of this paper, the human operators very much need to understand what control technologies are deployed and their transmission operations impacts.

Other transmission system control technologies that are based on power electronics, known as FACTS devices, have been around for roughly three decades, but their cost has limited their deployment. The cost of power electronics is dropping rapidly, even for those operating at transmission voltages and currents, so it is expected that the deployment of these devices will increase. There are three basic types of FACTS devices: shunt devices that can inject reactive power, series devices that can control power flow on lines, and HVDC facilities that can control the flow precisely (in addition to transporting power). Shunt devices are in common usage in the United States today for controlling bus voltages, and series devices (some even distributed along transmission lines) are being actively tried out. HVDC is heavily used in other countries but is not being investigated much in the United States mainly because of siting and cost-recovery issues. As the use of FACTS devices for controlling the system increases, these devices will become another set of controls the operator has to be aware of.

As more generation and control move into the distribution system, there is need to determine the appropriate level of aggregation of information about these resources and phenomena in the transmission control center. A source of potentially large amounts of data is the distribution management system, which often has information that goes all the way to the customer meters.

Traditionally, the EMS did not exchange much data with the distribution management system because the electrical energy flow was always one-way from the transmission substation to the distribution feeders which, in turn, fed the loads. The occasional phone conversation between the transmission and distribution operator was sufficient coordination. Today, with more generation and other energy resources being located on the distribution system, the flow of real and reactive power is not always one way. As a result, coordination between transmission and distribution operations is becoming more intertwined, so the control center EMS will need to exchange information with the underlying distribution management systems. How much information from the distribution management system can and should be sent to the transmission control centers and how it should be used is an open research question.

Transmission control centers are also receiving more and more data that do not pertain strictly to electrical energy. This includes weather and weather prediction data, which are needed for forecasting load and generation (wind and solar) as well as possible disturbances to the grid such as those caused by hurricanes, tornadoes, floods, and fire. Another growing concern is security of cyber systems (encompassing their entire supply chain) as more data from substation communication and monitoring systems are being gathered at the control center. Applications requiring such data are expected to grow in number.

Not everything can or should be processed at the control center level. Research is needed on the data flow affecting the entire electricity grid infrastructure, from edge-of-the-grid devices through the substations and distribution management systems to the TOP control centers and then ultimately to the RCs, also considering the previously mentioned non-electrical data such as weather information. Associated research is needed to determine the appropriate level of data aggregation and the trade-offs between faster communication and improved decision making. One area of research should be the potential to change traditional SE algorithms to allow for more distributed processing at the substations, perhaps in a time frame of cycles that could include some system dynamics.

The ultimate users of all the data and information are the human operators and engineers. In addition to research to improve the underlying algorithms in the devices, a key area of research is how best to keep human decision makers in the loop. Maintaining human situational awareness in the control room at all times is crucial. This is expected to be true for at least the next several decades. During normal operations, EMS tools, including their user interfaces, are usually adequate. In comparing control room environments across industries, it is important to understand that electricity grid operations are quite different from, for example, the circumstances experienced by many air traffic controllers. Electricity grid operators often work 12-hour shifts with no scheduled breaks whereas air traffic controllers' "on time" is usually no more than 90 minutes to two hours followed by a 30-minute break. This difference is attributable to the fact that, during the normal state, the electricity grid, from an operator perspective, is usually changing slowly, appearing to be at a quasi-steady-state equilibrium point in which most tasks are routine.

However, one never knows when sudden events can shift normal operations to alert, emergency, or *in extremis* conditions. As viewed from the New York control center, the August 14, 2003 blackout occurred in a few seconds during which the grid went from normal operations to a blackout covering much of the state. Not all emergencies manifest that rapidly; many unfold over time frames that would allow operators to intervene effectively. Research is needed on the best ways to synthesize, and present to operators, information from a growing number of sources, particularly during rare events. Information sources include raw data, such as from SCADA and PMUs; processed information coming from SE; and the output of a growing number of support applications such as RTCA. Avoiding data overwhelm is crucial. More intelligent alarm processing is needed. Of particular importance is research focusing on the algorithms and user interfaces associated with time-varying data. Effectively seeing the trend in the grid state—where the grid has been in recent past, and where it is likely to go—will be essential. Related to this is utilization of the large amounts of time-varying data coming from PMUs. Dynamic issues, such as low-frequency oscillations, can impact operations, and situational awareness must be maintained, including when the grid is not at a quasi-steady-state equilibrium point. Much of this research will probably be most effective if done jointly by those knowledgeable about the electricity grid and experts in human factors.

Although operators and engineers have more and more powerful aids, the power system itself is changing quite fast. The change in the mix and location of generation and the new technologies that can further automate grid operations are both making the system and its operation more complex. The new developments in monitoring, control, and decision-making technologies give operators more tools and information, but to act effectively using these new aids, operators also have to understand the behavior of this more complex system. Therefore, in addition to the technologies mentioned in this section, operators will also need training to keep up with these complexities. Subsequent sections of this paper describe recommended support tools and OTSs.

5. Engineering Tools to Support Real-Time Operations

As discussed in the previous section, the transmission control center is the hub of all transmission system operations, supervised by operators who utilize the SCADA-EMS to monitor and control the region under the center's jurisdiction. These computers gather data in real time, process/analyze the data, and display information to enable operators to make decisions about control actions. Some control actions are initiated by human operators, and others are implemented automatically by the computers. Some of the automatic control actions, such as simple protection or voltage control, are taken locally at substations without any initiation from the control center; others, such as AGC, are triggered by signals from the control center computers.

The operator bases manual control decisions on monitored real-time data. Computers can add information, such as limit-checking, to alert the operator, e.g., by setting off alarms. As SCADA-EMS computers have become more powerful, they have gained capabilities to further process monitored data, providing additional information to operators to support decision making. Two of these more sophisticated analytical functions, SE and RTCA, were mentioned in the previous section as analyses that are routinely available in most control centers today. Given the increase in complexity of transmission grid operations, more such analytical functions will be needed to support operator decision making.

Two factors are driving the need for more sophisticated analytical tools. One is the availability of PMU data, which are collected at rapid scan rates that can be tracked only by computers (not the human eye). To make the implications of PMU data understandable, these data require more processing than SCADA data do. The other factor is that the results from more elaborate analytical functions are difficult for operators to interpret, partly because operators have many duties, especially during system abnormal conditions, and partly because the typical transmission operator does not have the engineering background to readily understand these analytical results. In the United States, unlike in most other countries, it has been customary to rely on operators who do not have engineering training. Many power companies are now adding engineers to control center teams to assist with the increasing complexity of operations.

State estimators have used PMU data from the beginning, but, because SE is solved only every few minutes, only a very small fraction of the PMU data—that is, only PMU measurements that are a few minutes apart—can be used by traditional SE. As the number of transmission-system PMUs has grown, some portions of the transmission grid have become observable using PMU data alone. For example, the 345-kV system of ISO New England or the 500-kV system of the Western Interconnection are totally observable with PMU data. This means that the PMU data can be used to solve the state estimator of these portions of the system in sub-seconds (compared to minutes for traditional SE). Moreover, the PMU-only SE has two major advantages: one is that all the data are time-stamped, which means that the data input for solving this SE can be synchronized so that it doesn't suffer the errors that result from the time skew of traditional state estimator data. The other advantage is that the PMU SE equations are linear; this means that the solution does not require iterations, which can cause convergence problems. These linear state estimators are now being deployed and, at least in some locations, used in operations.

As most of the transmission system becomes observable with PMUs, linear SE will increasingly supplement traditional SE. That also means the downstream applications like RTCA can be run off of either the traditional SE or the linear SE results. Because RTCA can currently take minutes to run, the potential benefits of faster SEs, linear SEs, and RTCAs are topics for future research. One area of potential application is operator command authentication, in which real-time SE results coupled with faster-than-real-time simulations can be used to detect whether any of the supposed operator commands are spurious because of, for example, a cyber attack [31]. The application of SE and other data for real-time control is the focus of a companion paper in this series entitled *Automatic Control Systems*.

In addition to SE and RTCA, many other analytical tools can be made available to operators. One such tool is the operator power flow, which is usually available in EMSs. The operator power flow allows the operator to study what would happen to the real-time system if the operator were to initiate any change. This tool allows operators (or real-time support engineers) to use the power-flow case that is calculated by SE and represents real-time conditions in order to study the effects of any control action that the operator is considering.

Coordination of transmission outages is covered by NERC Standard IRO-017-1 [32], which states that each RC needs to develop, implement, and maintain an outage coordination process within its footprint. RCs' approaches to coordinating outages vary, and the approach also varies depending on the type of outage. For example, in ERCOT there are five types of outages: planned, maintenance, forced, opportunity, and simple [33]. Most of these are planned well in advance, with the outages studied at both the RC and TOP level, usually by engineers and the operator charged with implementing the plan that has been defined *a priori*. Depending on the RC, the operator could use the operator power flow to see what would happen when this outage takes place, based on current real-time conditions. However, this tool might not be used because most of the time the system is not heavily loaded, the outage has already been well studied, and the operator likely has a substantial amount of experience of taking similar actions in the past. Most challenging from an operations perspective are forced outages, in which an element needs to be removed quickly. Whether or not operator power flow is used depends on the particular TOP or RC, the EMS system set-up, and the criticality of the decision. One reason this tool is not always used is that it might require manual intervention to set up the operational case that one needs to study (unlike SE and RTCA, which run periodically and automatically without manual intervention).

Another analytical tool that has been researched quite extensively but has not been widely deployed is the calculation of corrective and preventive controls. The SE and the RTCA outputs alert the operator to abnormal conditions on the grid. The alarms provided by the SCADA system, backed up by the alerts from the SE, tell the operator what limits are already in violation. The operator has to immediately take corrective actions. For voltage violations, the corrective actions usually are changing transformer taps or voltage set points. For line overloading, the corrective actions usually require changing the generation pattern, which is a little more complicated than the adjustments for voltage violations because generation changes have to be coordinated with the generating plants. Usually, the operator takes these actions from experience, determining the new set points approximately by intuition. However, it is possible for an application to calculate the best voltage and flow changes and provide those possible solutions to the operator. This application could be based on an OPF solution and is usually referred to as "corrective control action" and triggered by any violations on the actual system.

A similar analytical tool, referred to as preventive control action, could be designed to be triggered by any violations that the RTCA finds for particular contingencies. Although the RTCA is a very useful tool to alert the operator to possible contingencies, the operator has to decide what actions, if any, should be taken once the RTCA has identified a contingency that could produce a violation. There are two possible ways to react to RTCA alerts: to do nothing but be prepared to take action if the contingency occurs, or to take action to alter the current condition to avoid the contingency. The first option assumes that the current system condition is normal. This latter option is a preventive control action, and could be implemented by an application that would also take advantage of an OPF solution. This would be a more conservative approach that is seldom used because it would invariably be more expensive than the first option. The more common approach is the first, in which no action is taken immediately, but corrective control actions are calculated for all the potential offending contingencies so that these actions are ready to set in motion if a contingency occurs. Because voltage and line overload violations always provide some time (many minutes) for the operator to act, this "wait-and-see" procedure is used even when the operator does not have corrective and preventive analytical tools. As the grid and its operation become more complex, operator experience alone might not be sufficient to take appropriate corrective or preventive actions, so access to analytical tools to support decision making will become more critical.

The tools mentioned above assume that transmission line overloading is a result of the line's thermal limit. However, in some power systems, the line limit is caused by transient stability that is lower than the thermal limit. The Western Interconnection, because of its longer transmission lines, has always been stability limited whereas the Eastern Interconnection has not had many stability problems until recently as higher loadings of the transmission system are changing its dynamic behavior. For dynamically limited systems, the RTCA, which is based on power-flow solutions, cannot detect stability violations. One way to compensate for the RTCA's inability to detect these violations is to run many off-line transient stability cases to determine the loading limit of the lines so that no instabilities occur. However, stability limits determined in this manner tend to be very conservative and result in operating the system with much lower line limits than necessary. Although this method was the only option available for some time, today the dynamic security analysis tool is used to augment the RTCA: the RTCA detects any thermal limit violations, and then the dynamic security analysis tool runs the transient stability analysis for the same contingencies to identify which ones cause instability. The dynamic security analysis tool is a common application today in some locations, but it requires more research to make it more robust to be applied all over the United States.

Another dynamic phenomenon that has adversely affected transmission system operations is sustained oscillations of low frequencies. This occurs because certain values of electrical variables in the grid excite natural resonance frequencies in some portions of the grid, often in rotating mechanical equipment. Although such oscillations are not new [34], there seems to be growing concern about them in all the major U.S. interconnections. These oscillation frequencies are too fast to be detected by the SCADA system and are, therefore, not visible at the control center, so they had to be detected locally at the generating stations. Controllers called power system stabilizers were used at the generator to damp the oscillations. However, sustained oscillations are now appearing on the Eastern and Texas Interconnections, sometimes associated with wind farms.

One aspect of this dynamic phenomenon that makes it easier to address is that each of the oscillation frequencies is known, and each frequency is typically associated with a portion of the grid. This means that if that an oscillation of a particular frequency is detected, the source of the oscillation can sometimes also be detected. The oscillation can then be controlled by changing the loading near that portion of the grid. In addition, the availability of real-time PMU data at control centers makes it possible to detect the oscillation (its frequency and damping) because the PMU scan rates are faster than the oscillation frequencies. Now tools are available in the EMS that can continuously scan for these frequencies in the PMU data, and, if damping of the oscillations is not sufficient, to transmit an alarm to the operator. In areas where such oscillations are possible, the operator has a list of actions that can be taken (usually lowering loading levels) to damp the oscillations. More research is needed to enable close-loop control such that, instead of operator actions, automatic control signals could be sent by the SCADA-EMS system to damp the oscillations. Until such closed control of oscillations is available, even some control advice from the SCADA-EMS to the operator would be a step forward.

Although traditionally sub-synchronous resonance has been a topic for longer-term power system planning, there is also growing concern about this phenomenon in grid operations [35], [36]. Sub-synchronous resonance is associated with the exchange of significant energy between the electricity grid and generators at one or more natural frequencies below the synchronous frequency. Sub-synchronous resonance is becoming more of an issue in some locations because of the use of transmission line series compensation in portions of the grid with potentially large amounts of inverter-based generation (e.g., wind and solar). Better engineering tools are needed to support both real-time operations and planning.

The new applications mentioned here are quite complex and will require regular engineering maintenance to keep up with the changes in the power grid as well as the computer and communication system that overlays the power grid. In addition, the results from these sophisticated applications, whether they are advisories to the operator or automatic control signals to equipment, can also be complicated enough that engineers with proper training will be needed in the control room. Training needs are further examined in Section 8. Considerations of new tools to help with *in extremis* operation are covered in Section 9.

In addition to managing the transmission system in real time, the TOP has to also plan for the near term—from the next hour through the next few days. In much of the country, generation is scheduled through the markets. In areas where auction markets do not exist, generation has to be scheduled using tools like unit commitment. Market rules and ancillary services definitions are changing over time, but market or schedule results are provided to operators monitoring the system in real time.

When an operator is looking ahead to determine scheduling, the forecasting of loads and wind/solar generation becomes important. Both depend on the weather. The weather is also important if inclement conditions could impact the grid itself. Operators have to brace for disturbances such as storms. In addition to following which parts of the grid may be affected by storms, operators might change many operational protocols in response to abnormal weather conditions. More reserves might be required, and a conservative approach of multiple- rather than single-contingency operation might be taken. Regional blackouts would require system restoration, so other resources have to be prepared to provide emergency response. Computer resources have applications that can help with restoration protocols, for example keeping track of repair crews and estimating repair times for damaged equipment.

Increased optimization of transmission topology needs research attention. For decades, transmission line switching has been an approach to dealing with operational issues, commonly involving the removal of some lines during periods of light loading to correct for high voltages, or removing a lower-capacity transmission line when it approaches its limit if the flow can easily be accommodated on other nearly parallel circuits. Recently the idea of line switching as a more generic topology optimization solution has been proposed and is being adopted by some [37], [38]. Usually these transmission switching scenarios are developed after extensive study in a long-term planning context. There is a need for more research on applying this approach as a flexible near-real-time solution.

There are also longer-term research needs associated with the design (planning) of the electricity grid. One goal of grid design is to ensure that the transmission system is robust enough to reliably transport electricity, at a minimum during normal and statistically likely contingent situations. It is easiest to address reliability as part of designing new, controllable generation when the anticipated load can be reasonably estimated, as was the case in much of the country prior to the 1990s. The challenge now is that the grid is rapidly changing, with retirements of existing generators, the addition of much more intermittent and therefore less-controllable generation on the bulk grid, the addition of potentially large numbers of DER embedded in the distribution system, and a potentially vastly different electrical load as transportation electrifies. There are a number of different research needs in this area (many of them described in [26]. We see the most important research focus areas as (1) application of stochastic methods, (2) renewed focus on understanding and simulation of electricity grid dynamics, and (3) machine learning applied in particular to a better understanding of future customer behavior. For each of these topics, the focus should be on research related to larger-scale systems.

6. Technologies to Enhance the Use of Historical Real-Time Data

There is an urgent need for research to make use of historical electricity grid data to support transmission operations. Transmission operations consume and generate vast volumes data; a significant percentage of these data are archived. The data come into the EMS via the SCADA system, come from PMUs, come from a variety of other sources including neighboring grid operators, and are generated by the EMS itself (including the results from SE and RTCA).

Historical data can be broken into two broad categories, short term and long term. Short-term data are associated with the current operating state and might range from near-real-time to perhaps up to 24 hours in the past. Control centers have long made use of short-term historical data. Prior to digital computers, historical data were kept in log books or displayed and saved using strip-chart recorders. These strip-charts allowed control room personnel to see how the various system values were changing in a quasi-steady-state manner. Typical values saved on strip charts included system frequency, total load, total generation, and others such as individual generator outputs, voltage magnitudes, and key flows. Except when displaying locally measured values (such as frequency), the strip-charts were updated based on the SCADA scan rates (every few seconds). Although mostly computerized now, strip-charts continue to be a key part of the EMSs at both the RC and TOP levels.

Short-term data are used in a variety of different algorithms and user interfaces. With the advent of PMUs allowing system measurements at 30 to 60 Hz, extremely short-term data can be used for near-real-time modal analysis and oscillation source detection. New SE algorithms are being considered that utilize short-term historical information and/or short-term forecasted information [39]. Contingency analysis could also be enhanced to utilize a similar combination of short-term historical and/or forecasted information to identify the appropriate contingencies to run and a dynamically determined probability of occurrence.

User interfaces need to be enhanced to take better advantage of short-term data, particularly as grids become more variable with the addition of large amounts of intermittent generation and dynamic load. For example, when operators change shifts, the short-term memory from the operators who are going off duty needs to be effectively transferred to the operators staffing the next shift. Effective overview displays coupled with much-faster-than-real-time animation loops could help transfer this knowledge. Variable playback rates, in which quiescent times were shown rapidly and the more interesting periods shown slowly, would help make data easily available to operators. During operations, similar technologies could be used to review the recent past, coupled with simulations integrating short-term forecasts to show how the grid is likely to evolve. This should be an important research focus area.

Switching to the topic of long-term historical data, the electricity grid state is constantly changing, and no two days or even minutes are exactly alike. However, many aspects of grid operations are repetitive and routine, with strong daily, weekly, and seasonal patterns. Therefore, longer-term historical data can be quite helpful in providing insights into appropriate control actions. Experienced operators rely on this type of information all the time, leveraging their past experience, insight, and wisdom in their decision making. This information is also embedded in many of the operating procedures that operators and engineers use to make real-time decisions. Although many detailed procedures are understandably not public, a flavor of these types of procedures is described in [40]. A standard operating procedure format is “if-then” conditionals; e.g., if the flow on Interface A is above xx MW, then the operator should open Generator B. Similar to what an experienced operator would do, the procedures combine real-time information with wisdom gained from past experience and often also from many engineering studies. The research challenge is to figure out how much of this process could be automated to deal with situations not covered by these procedures.

Load forecasting is a common and quite successful application of historical data. An accurate day- (or few days-) ahead forecast of electrical load is crucial in both near-term operations planning and real-time operations. Load forecasts are used by many different entities in electricity grid operations, from the RC level down to the distribution system (the interface between the transmission and distribution systems is the focus of the companion paper in this series entitled *Distribution Integrated with Transmission Operations*. Over the years, many different techniques have been proposed for these forecasts; this is a classic application in which machine learning could be of great benefit. Load forecasts combine historical information about the electricity grid and other key drivers (e.g., weather conditions, time of year, holidays, whether a university is in session) with future-condition forecasts. The load forecasting problem is to some degree simplified in that it has relatively few outputs, and they do not depend strongly on electricity grid topology.

Similar historical information sets are used in forecasts of renewable generation output; this is also an application in which machine learning could be of benefit. In considering research on forecasting renewable generation output, it is important to differentiate the parts of the problem that depend on accurate weather forecasts. This research would best be done by meteorological experts.

For real-time transmission operations, giving operators and engineers who are facing a grid event rapid access to information about similar situations in the past could be of great help. How much this process could be automated based on machine learning and used for autonomous control is very much an open research question. Typically, machine learning algorithms require large amounts of prior information that adequately cover the desired solution. A challenge with transmission grid operations is that, because of routine maintenance, unexpected events, new construction, and generator commitment decisions, the topology of the transmission system is constantly changing, so historical control actions might not be valid for present-day events. This is not meant to imply that machine learning could not be useful, but research in this area needs to recognize the dynamic nature of transmission topology. Proposed algorithms need to have sufficient scalability to handle the large solution domain that would likely be encountered in practice.

An important consideration for doing research on the application of historical data is that in many cases only a very limited amount of actual operational information is available to researchers. As mentioned in Section 2, present-day transmission operations technologies could be summarized as impressive, complex, potentially opaque, and vital. These characteristics certainly apply to historical data and the associated models. The raw data and EMS software outputs that are currently being archived at the RC and TOP level are certainly impressive, and making sense of this information is a complex task. Except for staff working directly for RCs and sometimes TOPs, the word “opaque” would also apply; at best, most researchers can only see a subset of these data, usually a very small or empty subset. Our purpose here is not to argue that more data should be released. Often this opaqueness is necessary, and, as researchers in this area, we know that with the newer data analytics being developed, researchers might able to gain insights that the data owners definitely would not want disclosed. Rather, our purpose is to highlight that this opaqueness is hindering research and needs to be addressed. One approach, now commonly used, is for the owners to disclose some information, often scrubbed and devoid of the metadata context that would be available in an actual application. An example would be providing PMU data without access to the PMU’s electrical location or the associated electricity grid models. Some research can be done based on these data although its applicability could be limited, and results might even be counter-productive since in an actual installation the full information would be available. A load forecasting analogy would be to try to forecast load using historical data devoid of meteorological information. An alternative approach that we expand on in Section 9 is to develop high-quality synthetic (fictional) grid models and data sets. This approach has the advantage of the input data and models being free of CEII and privacy concerns, which would enable the broad research community to have access.

In conclusion, we believe that historical information can be quite helpful in developing better electricity grid models. However, this requires that the information be effectively shared between operations and planning. This transfer might seem as if it would be simple, but, historically, it has been quite difficult. Part of the difficulty has to do with the difference in the way that electricity grid models on the operations side represent the system versus the way that models on the planning side represent the system. Operations models use a node-breaker approach, which shows all of the actual devices in the substations, including many that have almost no impedance (e.g., circuit breakers and disconnects). These low-impedance devices are then modeled as being connected at electrical nodes. This representation of all devices is appropriate for operations where the device status is known because of information provided by the SCADA system (or sometimes manually entered by the operators). Control-center EMS software tools have been designed to work with this detailed representation. By contrast, on the planning side, the grid is represented using a bus-branch approach in which the electrical nodes joined together by the low-impedance devices are aggregated into buses, and only the higher-impedance branches (e.g., transmission lines and transformers) are represented. This is appropriate for planning, which does not normally need specific substation topologies that might not even be known when planning is focused on future modifications. Software in the planning area has been developed to work with bus-branch representations. In recent years this chasm between the two types of models has been closing some as planning tools have been enhanced to better support node-breaker models. Still, a gap remains. Although this might not be a top research priority, it warrants attention.

Assuming the availability of historical real-time data and electricity grid models, an important research focus would be on using this information to improve the models, especially in regard to aggregate load as seen at the transmission level. Modeling the aggregate electrical load presents challenges because:

1. It is composed of many individual electrical loads, some of which can be quite complex.
2. The composition of the aggregate load is constantly changing and can differ substantially over time (e.g., the load on a summer afternoon is likely quite different than load on a winter night).
3. What is treated as aggregate load in transmission-level analysis consists not only of the load itself but also control devices such as switched shunts in the distribution system and, increasingly, more distributed generation (e.g., solar PV).
4. Behavior of load under extreme conditions such as low voltage is only apparent during system disturbances.

Because of the above challenges, how to use large amounts of real-time data to develop appropriate models for a variety of difference applications (e.g., power flow, dynamic simulations) is an important research question.

7. Technologies for Engineering Tools to Support Transmission Planning

In the previous section we discussed the use of historical data in off-line applications to enhance transmission operations and operations planning. Historical data are also very useful in long-term planning, which is the focus of this section.

The goal of planning is to ensure that the transmission system is robust enough to, at a minimum, reliably transport electricity during normal and statistically likely contingent situations. Designing for reliability is easiest when integrated with the design of new controllable generation and when the anticipated load can be reasonably estimated, as was the case in much of the country prior to the 1990s. The challenge now is that the grid is rapidly changing, with retirements of existing generators, the addition of significant amounts of intermittent—and therefore less controllable—generation on the bulk grid, the addition of potentially large numbers of DER embedded in the distribution system, and a the potential for a vastly different electrical load as transportation electrifies. Of the numerous research needs in the area of long-term planning (many of them presented in [26]), we see the most important focus areas as (1) long-term forecasting of both generation and load, (2) the application of stochastic methods in determining long-term scenarios, (3) a renewed focus on understanding and simulating electricity grid dynamics of the future, and (4) the application of machine learning particularly for understanding future customer behavior. For each of these topics, the focus should be on research associated with larger-scale systems.

The deregulation of generation has increased uncertainty about predicting future generation mix and location. The generation mix is changing, with coal plants closing and wind and solar generation increasing, making the sizes of the generators and their locations are more difficult to forecast. Moreover, much of the solar generation that is being added to the grid is connecting to the distribution system rather than the transmission system. These factors create significant uncertainty in forecasting generation beyond about three years into the future, which, in turn, makes transmission planning very difficult. Tracking of grid resource adequacy falls on RCs by default, but the uncertainties regarding generation installation and availability make loss-of-load calculations much more difficult, requiring improved analytical tools.

Like generation forecasting, load forecasting is also becoming more uncertain because customers can provide self-generation, e.g., roof-top solar, and can control their loads with new technologies for energy conservation as well as cost minimization. In addition, the adoption of electric vehicles has been hard to predict, and clustering of electric vehicle adoption adds to the forecasting error. Loads are also impacted by the adoption of storage devices such as batteries and controllable thermostats and water heaters.

Before the 1990s, when all power companies were vertically integrated, it was common to plan transmission 20 or 30 years into the future, which allowed enough time for constructing expanded facilities. With the push toward decarbonization and the rapid evolution of new technologies as well as the uncertainties mentioned above, the old planning methods cannot provide designs further into the future than 3-5 years. This creates a major hurdle for planning a new transmission line or a large generating plant because construction times for these facilities are longer than 10 years.

To support longer-term planning, research is needed to enable forecasting of scenarios rather than specific generation and load values. As the longer-term future becomes more uncertain, the best strategy will be to plan for flexible grid designs that could handle a range of scenarios rather than focusing on single specific scenarios. The modeling and simulation tools needed for scenario building are not available yet, but the computer resources are available to rapidly simulate many grid architectures and enable planners to bracket the different possibilities. For example, some scenarios might allow transmitting more energy from greener regions to areas where solar and wind are scarce whereas other scenarios might suggest more local generation (at the grid edge). Generating, evaluating, and optimizing these scenarios will have to be automated because the number of variables (technologies) to be considered makes it impossible for expert engineers to carry out the process manually. The closest tools we have today for such studies are production-costing tools that are used for planning studies, but these tools are not set up to generate and rapidly evaluate numerous scenarios or handle the vast array of new technologies—storage, active loads, roof-top solar, etc.—that contribute to even more alternatives.

As noted, uncertainty in forecasts increases as the planning horizon increases, so a promising approach is to use stochastic methods for analysis. Research is very much needed in stochastic methods applied to power systems because the history of using probabilistic methods for power system planning is limited. Although the calculation of loss-of-load probability has been a tool in generation planning for decades, similar methods have not been effectively applied to transmission planning. The loss-of-load probability calculation worked well when generation planning entailed studying a small number (dozens) of central generators, but this approach does not work very well when applied to hundreds of small distributed generators. Also, if using stochastic methods for transmission planning has been considered a challenge, such methods will be even more difficult to use for the combined transmission and distribution systems. Thus, this challenging analytical research is very much needed.

Monte Carlo methods have been quite successful despite being derided as a “brute force” rather than an elegant analytical approach, and the availability of faster and more powerful computers has made it easy to run thousands and thousands of cases, which makes the Monte Carlo approach very feasible. Instead of depending only on research for analytical probabilistic methods, practical methods and software using Monte Carlo algorithms should be developed. Given the complexity of the models for all of the new transmission and distribution technologies, this is not going to be a trivial task; both modeling skills and numerical method development will be required.

Modeling of the future power grid will continue to be a challenge as new technologies, for both power electronic equipment and communications and control, are being rapidly developed. However, modeling is required for both system operations applications used in the control center (see Section 5) and for power system planning. Models for planning pose a bigger challenge because it is very difficult to predict the technological advances of the next 20-30 years.

An added issue is the changing dynamic behavior of the grid. Inverter-connected, non-synchronous generators are making interconnections that have been inherently stable, like the Eastern Interconnection, less so because the rotating inertia of the system decreases with the closing of central generators, and the addition of power electronics sometimes produces oscillations. Studies of the

Eastern Interconnection have in the past been limited to steady-state analysis, but studies of dynamic behavior are becoming more important, making research on dynamic models and simulations very important. An added concern in this area has been the availability of equipment models from vendors who often consider this information proprietary. Appropriate reliability standards are needed to make this information available when the model affects the behavior of the whole system.

Machine learning and data analysis can make a significant positive contribution to the modeling and forecasting tasks mentioned above. Section 6 discusses the research needed in this area. However, the application of historical data discussed in Section 6 is to system operations, for supporting real-time operations tasks. For power system planning, similar machine learning tools can be used on longer time series of historic data to identify evolving grid behavior over the years of the planning horizon. There will also need to be more coordination between the transmission and distribution systems, but that is the focus of a companion paper in this series, entitled *Distribution Integrated with Transmission Operations*.

In the United States, transmission planning is mostly regional. For example, the Eastern Interconnection is divided into several planning regions, each of which does its own transmission planning. In recent years, this planning has become less effective as the coordination between the regions has mostly not been strong enough to support joint studies. Therefore, some of the responsibility for planning has fallen on the Eastern Interconnection RCs, who are trying to coordinate more closely through associations like the National American Transmission Forum. The Western Interconnection, which used to be one RC, has now been divided into four RCs, creating a new planning coordination challenge. This coordination would be facilitated by standardization of models and data within the same interconnection so that the studies and simulations are interoperable.

We believe that, as electricity grid models become even more complicated, it will become more challenging to ensure that the individuals doing the studies understand what is going on, or, to borrow a phrase used in earlier sections, that staff performing the studies have good situational awareness. That is, it will be challenging to ensure situational awareness of what is happening in the large-scale, often quite complex, static and dynamic studies used in transmission planning. The situational awareness challenges of such studies depend on many factors, including the electricity grid size, the complexity of grid models, whether there are contingencies or RASs considered, and the desired application. In some situations, such as the small models often used in engineering education and some research, situational awareness needs are modest. In addition, if the desired application is for the purpose of determining whether the results of perhaps thousands of contingencies meet a criterion (e.g., voltage recovery following a disturbance) then, likewise, the situational awareness needs are modest. However, for some planning studies there is a need to provide the engineer with a detailed understanding of total system response. This area merits research.

8. Training Simulators

Training of electricity system operators has been important since central control rooms were established in the early 20th century. The first control rooms were hard-wired with analog systems that required the operator to have some understanding of power system behavior. Operators had to take action to control frequency, to balance generation and load, and to control voltage. Keeping the power system within normal limits required constant supervision. Most training was done on the job, augmented by some classroom teaching of power system components and their behavior. Operators were not engineers but were chosen from technician staff, so classroom lessons were based on simple formulas rather than math and physics.

This form of training continued even after digital computing and communications were introduced to the control center. By the 1960s, computers were powerful enough to simulate mathematical models of the power systems that were not too large. These were batch computers (meaning they solved one set of equations sequentially), so they were not suitable for the SCADA systems in control centers, which continually streamed measurement data. SCADA computers operated in real time and processed data but were not efficient at solving equations. During this period, operators received some training to familiarize them with displays and control procedures, using dummy consoles that were not connected to the real system.

A full-fledged training simulator for operators requires a model of the power system that runs in real time so that the trainee can take control actions on the console and see the resulting changes in voltages and power flows on the displays. The first OTS, which became commercially available in 1977, ran on the SCADA-type processing computers; the power system that it could model had to be small (fewer than 100 buses) because of the limitations of the computers. (This is analogous to saying that the training simulator for a Piper Cub became available when the airlines were already flying Boeing 707s). However, these early simulators were quickly utilized for generic training, which was further encouraged after the New York City blackout that took place later in 1977.

A breakthrough came in the early 1980s with the advent of the interruptible computer design, which replaced batch computers, and new physically smaller workstations. These workstations could do the tasks of both the SCADA data-processing computers and the EMS batch-processing scientific computers and became the new workhorses of the control center architecture. They were also ideal for the OTS because they could simulate power system models in real time as well as process and stream simulated data in the same manner as the data acquisition system. Thus, a new generation of OTSs became available in the 1990s, which were powerful enough to simulate real-size power grids. Since then, computer power has further increased to be able to simulate, in real time, any transmission grid in the world.

The basic structure of the OTS has not changed over the decades. All OTSs have three modules:

1. The **power system module**, which models the behavior (physics) of the power grid by mathematical equations and simulates the model in real time
2. The **control center module**, which mimics the control center environment, from the physical layout to the display formats
3. The **instruction module**, which sets up various scenarios for training, tracks the trainee's actions, evaluates the learning that takes place, and provides this information to the instructor

The effectiveness of the OTS depends heavily on the characteristics of these modules. Although NERC standards require training and certification before operators are allowed to actually operate the power grid, these standards are vague about the level of mastery needed. The standards do not mandate simulation training (although it is strongly encouraged), and they do not specify the quality of the OTS modules.

For high-fidelity training, the power system module should mimic the actual power system that is under the jurisdiction of the control center in question. Much of this model is already used in the EMS, so it is mostly available, but some behavior of the power system, especially dynamic behavior, requires other models (equations) that are not in the EMS. It has to be remembered that, as the transmission system changes over time, the EMS data base has to be updated, and, if a model of the real power system is used in the OTS, it has to be updated as well. Some power companies do not use a full model of their power systems and instead opt for a generic (synthetic) model. Generic training can be done on such an OTS, and many concepts, such as frequency and voltage control, can be demonstrated. Some power companies use generic OTSs for training, and some training organizations also conduct such training for power companies.

Having a training facility that duplicates the actual control center environment would be expensive although some ISOs/RTOs and larger transmission owners have such facilities. More often, the power company may only mimic a couple of the operator consoles in the training facility rather than the whole control room. Without a complete set of the operator consoles, large wall displays, and communication and other peripheral amenities, it is difficult to do comprehensive training of a control center's set-up.

The most important and difficult part of the OTS is the instruction module. For training on a generic power system, the instructional scenarios are all canned and focus on generic concepts of balancing generation and loads, controlling voltage, and similar fundamental actions. The advantage of having the real power system modeled in the OTS is that realistic scenarios can be set up for training. Particular emergency scenarios that have actually occurred can be captured from historical EMS data and used as training scenarios in the OTS. Generating new scenarios that are designed to train for particular types of abnormal operations is a difficult task that requires highly experienced operators and engineers. Another major task of the instruction module is to track a trainee's learning. More work is needed on both control-center specific scenarios and trainee evaluation, especially the utilization of machine learning techniques for scenario building and training evaluation.

In the United States, there has been no significant research on building improved simulators during the past couple of decades, and it is unlikely that any effort will be made to build better OTSs unless FERC/NERC require more rigorous operator training. As long as the operator licensing requirements stay as they are today, there appears to be no reason to build a better OTS. (This is analogous to saying that the airlines would not invest in high-fidelity simulators for the new sophisticated airplanes unless the Federal Aviation Administration required them to do so.) However, it is well understood that the increasing complexity of the power grid and its operation are outrunning the abilities of present-day operators. Countries like China are already building better training simulators than those available from vendors in the West who, in turn, do not see a market for more sophisticated simulators.

Of the elements of the OTS needing improvement, the control center module is the simplest. All that is required is to invest in a duplicate of the existing control room technology.

The power system module could be made much more sophisticated than it is in current OTSs because the amount of computer power available (cheaply) today is several magnitudes greater than when power system simulations were first built during the 1990s. The main deficiency in simulation models now is that most of the simulations are based on quasi-static models rather than a full dynamic model that can replicate the transient electro-mechanical behavior of the power system. Today's computers can handle existing simulation methods in real time, but the integration of these simulations into existing OTSs will require some clever manipulation of the simulation methods. In addition, without accurate simulation of transient behavior, the model cannot generate the PMU measurement data, without which the training will remain partially blind.

Two recent developments could impact the power system module and be the foundation for future research. The first would be the application of electromagnetic transients program-type simulations, first presented in [41], which use very small integration time steps, often on the order of microseconds. In this approach, transmission lines are modeled with the differential equations associated with the voltage and current relationships in inductors and capacitors. By using trapezoidal integration techniques, the models reduce to a network of coupled current sources and shunt resistances in which transmission line propagation delays can be considered explicitly. However, with simulation step sizes of microseconds, these simulations are often limited to smaller systems unless large amounts of parallel computation are used. The second development would be to leverage the newer interactive simulators that are being developed based on existing dynamics code, with integration time steps on the order of ¼ or ½ cycle. An example is given in [42]. Such packages can run simulations with up to several thousand buses in real time. Access to such simulations needs to be provided to the many different classes of people working in the electric power industry, including engineers, policy makers, and students.

Many other power system models will require upgrading and new developments. The distribution system, which appears as a load to the transmission system of the OTS, is undergoing huge changes that require fundamental changes in OTS load modeling. Moreover, the increase in generation located on the distribution system shows up in the OTS as negative but controllable loads to the transmission system. The modeling of neighboring transmission systems also requires improvement.

Improvements in the instruction module are needed not from research in modeling and simulation but from research in pedagogy. Much can be borrowed from military training simulators (the applied science is most advanced in military applications) and from other industries such as airlines. Better power system modeling will also help in building more effective training scenarios, but the emphasis in this module is the effectiveness of the training process itself, not the fidelity of the models.

It is also important to broaden the application of OTSs beyond the utility operations community. The electricity grid impacts essentially all other infrastructure in society, so many of the people involved with other infrastructure could benefit from a better understanding of the grid. This includes those involved in government emergency operations, policy makers, and other influencers. Exposing these individuals to high-quality electricity grid simulators could aid them in understanding the complexities of the grid and the interaction between policy decisions and grid operations. Of particular importance would be simulation of the high-impact, low-frequency events covered in Section 9. This expanded educational mission could best be undertaken by universities and national labs.

9. High-Impact, Low-Frequency Events; Restoration; Coupling with Other Infrastructure

Society depends upon a reliable electricity grid, and this dependence is likely to increase in the future, particularly with the expected electrification of transportation. Blackouts cannot be totally eliminated, but their frequency and duration can be decreased. However, the societal impact of blackouts is not a linear function of their size or duration. Small or even medium-size events, although disruptive, usually do not have a significant societal impact, particularly when the affected customers understand the cause of the interruption, such as severe weather, and if the outages do not occur at times of stress, such as during extreme cold or hot temperatures. The industry also has a long and mostly successful track record of quickly restoring service following disruptions.

However, some events are of such magnitude that their impact on the electricity grid and on society as a whole could be catastrophic. In a joint 2010 report, NERC and DOE labeled these “High-Impact, Low-Frequency” (HILF) events [29]; others have called them Black Sky Days or Black Swan events. Characteristics of HILF events include some combination of large size, long duration, and potentially catastrophic societal impact. HILF events can occur initially in the electricity grid and then spread to other sectors of society, start in another sector and spread to the electricity grid, or simultaneously affect both. Germane to the crises of 2020-2021, one of the HILFs identified in [29] was the combination of a pandemic and the cold weather impacting the grid [1]. In the pandemic scenario of [30], the pandemic affects the electricity grid workforce, making it increasingly challenging to continue operating the transmission grid, which results in blackouts. Thankfully, this scenario did not occur during the COVID-19 pandemic, but, if it had, the effects of the pandemic would have been even more catastrophic than they have been.

Of all the issues considered in this white paper, we believe that mitigating the impact of HILF events needs to be the highest priority. As their name indicates, these events are infrequent, but they do occur, and, when they occur, their costs can dwarf those of normal operations. The research directions we propose to increase the resiliency of the electricity grid to HILF events build on the contributions of [1] but are restricted to this paper’s focus on transmission operations (many of the ways to increase resiliency that are identified in [1] fall within the scope of the other white papers in this series). Within the operations focus, the research needs can be broken down into four categories:

1. what can be done prior to the event
2. what can be done during the event
3. what can be done after the event
4. what can be done in relation to the grid’s coupling with other infrastructures

As noted earlier in this paper, the transmission grid has been thought of as operating in one of five states, described in [8] as normal, alert, emergency, *in extremis*, and restorative. Building on what is presented in [30], in the aftermath of an HILF event the grid could be thought of having a sixth state, perhaps best denoted as a “new normal.” The new normal state, which could last for weeks to years, would be a time during which all normal electrical load could not be met. An example of such a situation on a relatively small scale occurred in Auckland, New Zealand in 1998 when 110-kV cable failures required most of the 74,000 living or working in the central business district to relocate for about a month. As a society we are currently living in a new normal resulting from the COVID pandemic.

The first research focus is on what can be done prior to an HILF to make the transmission grid more resilient. Resiliency should be assessed in terms of particular events, that is, by asking the question, “Resilient to what?” Four types of events were identified in [29], with the list expanded in [1]. Each has its own characteristics and to some extent requires its own mitigation strategies. However, there are some important commonalities. Prior to the event, the most important commonality is improved ability to simulate HILF events. This is challenging because many of these events have not occurred, and, even within a particular event class, there can be tremendous variability. In addition, a wide range of scenarios needs to be considered. Broadly, this could be thought of as resilient system design. For example, could different grid architectures be used to reduce the criticality of certain points of failure (e.g., critical substations)? The results of these simulations could then be used to determine any needed procedures for dealing with the event during operations. Not every event can be fully mitigated, but realistic plans need to be developed beforehand. The development of these scenarios and subsequent plans requires a wide range of *a priori* research. Even in aggregate, such research is almost always much, much less expensive than even one of the events it seeks to mitigate.

An important aspect of doing these simulations is to recognize that they are often inherently interdisciplinary. An example is the work done during the past decade to address HILF geomagnetic disturbance events, which have been known since the 1940s to have the potential to disrupt the grid. An HILF geomagnetic disturbance event actually caused a blackout in Quebec in 1989. Geomagnetic disturbances, which are caused by corona mass ejections from the sun, impact the transmission grid by causing quasi-DC, geomagnetically induced currents on the high-voltage transmission grid that, in turn can saturate high-voltage transformers, resulting in a wide-scale voltage collapse or transformer damage (or both). As a result of work during the past decade led by NERC and the Electric Power Research Institute, with funding provided by DOE and the National Science Foundation, the industry is now well on its way to addressing this threat, from both planning and operations perspectives. However, to accurately model geomagnetically induced currents and assess their risk, it is important to understand both how corona mass ejections interact with the earth’s magnetic field and how the changes in the earth’s magnetic field interact with the earth’s crust conductivity to induce the surface electric fields that cause the geomagnetically induced currents. This has required substantial interaction with the geophysics research community.

Therefore, one research direction would be to assess the already-identified HILF events and determine the requirements needed to adequately simulate them, including the expertise required from other domains. There should also be an assessment of whether these initial simulations are best done using actual grid models with their inherent CEII concerns, or whether it would be best to use synthetic grids. For some classes of events, particularly those that are human induced such as high-altitude electromagnetic pulses or attacks (physical, cyber, or combined), publishing research results from actual grid models could be particularly problematic. An important aspect of this work would be to not underestimate the potential impact of the event but also to appropriately weight the likelihood of the event versus its mitigation costs. In some instances, such as a geomagnetic disturbance or high-altitude electromagnetic pulse, the best mitigation operating procedure could be to de-energize some equipment to prevent damage.

Simulation of HILF events would be a cross-cutting issue because these events affect all of the domains addressed by the white papers in this series. Most germane to transmission grid operations would be research to enable training simulators to appropriately represent these events, including, for some events, their faster dynamics, and to ensure that operations software can handle these events. One approach could be the one presented in [43], in which environments are constructed where third-party simulators represent the HILF events, providing input into research-grade or commercial EMSs. Such environments could be used to give HILF event simulation experiences to a variety of different audiences, including electric utility engineers and operators, policy makers, researchers, and students.

Another research direction would be to determine the planning changes and operating procedures needed to intentionally and adaptively island the existing transmission grids. As noted earlier, large-scale interconnections can have some significant advantages, but, during times of system stress when there is a high likelihood of a cascading failure, there could be advantages to breaking these larger interconnections up into smaller, asynchronous parts through a process known as "intentional islanding." The number and composition of these islands, and the criteria and procedures for creating them, should be a research focus. Given the potential complexities associated with intentional islanding, enhanced planning tools are needed to develop, ahead of time, potential approaches to anticipated system conditions. For some scenarios in which fast control is needed, the intentional islanding would need to pre-specified in the protection system with the previously mentioned RASs (a topic covered in the *Automatic Control Systems* White Paper. Others islanding protocols could be developed that human operators could implement in real time, taking into account system conditions that might be different from those anticipated during prior planning. Complementing this intentional transmission-level islanding could be distribution system changes, a topic of another white paper in this series entitled *Distribution Integrated with Transmission Operations*.

Associated with the creation of the HILF event scenarios, there may need to be research regarding increasing the resiliency of existing EMSs to deal with these events. As has been previously noted, two of the four primary causes of the August 14, 2003 Blackout were failures in the affected EMSs. These included failure of state estimators to converge, data overwhelm caused by RTCA generating too many violations, and a human-machine interface that led to a lack of situational awareness. Although much has been done to address some of these issues, it is important to realize that immediately prior to the August 14th event, the general feeling in the industry was that the system was well monitored and that the EMSs of the day were impressive. The importance of the state estimator solution to many EMS functions is well known, with [44] providing a documentation of EMS failure events between 2013 and 2017 (a total of 318 events lasting more than 30 minutes, of which 113 specifically mention the state estimator or RTCA) and [45] providing additional details on the need to augment the existing state estimators to better handle system dynamics. Overall, there is little in the literature to reassure us that existing EMSs would be able to avoid failure during the potentially severe operating conditions of an HILF event.

A final research topic for the time period prior to an HILF event is an assessment of the value provided during the HILF event both by the transmission grid to customers, and by customers to the transmission grid. This is relevant to the increasing number of customers who are receiving much or even all of their electricity from self-generation. However, during some HILF events, these customers might desire or need to obtain their service from the transmission system or might be able to assist the grid. There are costs to transmission operations associated with mitigating the impacts of HILFs; this research would help to ensure that these costs are equitably assigned based on potential benefit.

Moving to the topic of real-time operations, for some HILF events, operational decisions will be of less consequence (such as during a long-term weather event affecting generation supply, for example, a drought, as mentioned in [1]). For many events, what can be crucial is whether or not effective control actions are taken, particularly during the event's early stages. Not much research has focused on maintaining situational awareness during these *in extremis* operating states. Data analytics and visualizations could be essential for providing operations personnel a wide-area view of the system during an HILF event. The operating conditions could be quite different from what they were during past experiences, potentially greatly reducing the usefulness of pre-defined operating procedures. In addition, operator intuition gained from decades of experience could actually be counter-productive. To do effective research in this area, it will be important to develop a simulation infrastructure to show HILF events on larger-scale systems, and to have a broad research team, including experts on the electricity grid and experts in human factors. There will also be a need for specific control center software enhancements, such as integrating real-time information about the grid's cyber and communication infrastructure [46]. All of these areas are important and should be the focus of research.

With respect to restoration in general, there are a number of potential research issues although many are not directly relevant to this paper's scope. However, three are at least partially operations related. First, following an HILF event or even a lesser event, damage will need to be assessed and a specific restoration plan developed. With the now-widespread availability of distributed visual sensors (often with global positioning system capabilities), including security cameras, individual cell phones, and drones, there could be lots of inputs to help assess damage. However, there is a need for research in how to use automated visual analytics and other strategies to deal with this potentially large set of information. Research is also need on creating restoration plans under a wide variety of scenarios. Second, in the event of a total blackout of at least parts of the grid, utilities would need to implement their black-start procedures. Most of these should be applicable during HILF events, but research might be needed on black-start procedure alterations based on particular HILF scenarios. Third, it is possible that the grid could be only partially restored, operating at a "new normal" for weeks to years. Of particular concern in this situation is damage to high-voltage transformers. How to operate a grid under “new normal” conditions without damaging transformers is a research topic.

An important research consideration is how to learn from blackouts and restoration after large events. Learning the lessons from an event requires beginning an impartial investigation as soon afterward as conditions warrant. One example of how this was done right was the August 14, 2003 Blackout. Within days after the event, DOE had assembled investigative teams that were on site at the likely responsible entities, with some teams conducting interviews with control room staff within the first week while memories were fresh. To ensure impartiality, many of the team members were drawn from universities and national labs. For future events, it is important to have trained, impartial teams available to respond quickly. There is also a need for research on how best to conduct a blackout post-mortem analysis and to convey lessons learned [47]. One specific research need would be in the area of event reconstruction, and to determine how simulation models can be improved to better match what actually occurred.

A last consideration is the coupling of the electricity grid with other infrastructure and disciplines. The electricity grid enables many other types of infrastructure and is in turn enabled by many of them. It also couples with many other disciplines, such as meteorology. Consideration of these couplings is a cross-cutting area of research, some of which is directly within DOE’s scope and some of which requires coordination with other entities such as the National Science Foundation. From an operations perspective, probably the most important coupling is with meteorology because weather data and forecasts are key inputs in control centers. Historical couplings were between load prediction and severe weather impacts. In many parts of the country, this coupling will grow in importance as more generation is provided by wind and solar, resulting in an enhanced need for short- and long-term forecasts. Another important coupling is of operations and natural gas infrastructure; [48] shows how hypothetical natural gas infrastructure failures could become the largest electrical contingency within time periods on the order of dozens of minutes. Many of the couplings with other infrastructure would become most important during times of system blackout and restoration. These include couplings between the electricity grid and water, transportation particularly as it electrifies, and cyber operations and communications.

A research need in this area is to determine how best to simulate the interactions among the different types of infrastructure. A starting point could be the visioning process recommended in [1], with “the objective of systematically imagining and assessing plausible large-area, long-duration grid disruptions that could have major economic, social, and other adverse consequences, focusing on those that could have impacts related to U.S. dependence on vital public infrastructures and services provided by the grid.” There would be a need to develop the appropriate points of coupling between federated simulation models of the different infrastructures.

10. Research Infrastructure

This section provides general background and suggestions for improving the overall research infrastructure in transmission operations. Currently there are three major types of research entities: industry, universities, and the national labs. Historically, much initial transmission operations research, both applied and theoretical, was done by utilities and equipment suppliers and documented in journals. Notable examples include the description of tie-line bias control by Nathan Cohn from Leeds & Northup Company (with a number of discussions from other industry engineers) [49], the description of sparsity by Sato and Tinney from the Bonneville Power Administration [50], and the vision for the EMS by Tomas Dy Liacco, then with Cleveland Electric Illuminating Company [5]. Gradually these types of papers were supplemented by studies written by university authors, including many classics such as the vision for LMP markets by Caramanis, Bohn, and Scheweppe from Massachusetts Institute of Technology [51]. Work by researchers from the national labs is more recent as the labs have been transitioning from their early focus on nuclear weapons. The literature from previous decades fairly comprehensively covers key transmission grid operations technologies and how they were actually being used by industry over time.

A concerning trend in recent decades has been the transmission operations industry's move away from documenting its work in journals or conference papers, and a subsequent substantial rise in the number of papers that have limited practical relevance. We recognize that paper content, authorship, and quality are sensitive topics, and we want to emphasize that some papers are high quality, strongly theoretical papers that have their place, and some highly speculative papers are to be encouraged. At the same time, there is a need for more papers that focus on the research challenges associated with the large-scale, complex transmission grids and their associated control infrastructure. It would be a step in the right direction to have more papers published that are rooted in observations of the actual grid or that deal with real complexity of the grid and that recognize that a simple mathematical construct to reflect the reality of the grid does not exist.

It is hard to know for certain what has caused the diminishing presence of papers authored by industry researchers; perhaps it is due in part to a restructuring in the industry that took focus away from research. Universities stepped into that role, and the number of academics who have substantial interaction with the actual grid decreased. In addition, industry organizations, such as the ISOs and NERC, took over some of the role that had been played by the technical societies and their publications. In addition, the rise of CEII, market sensitivities, and privacy concerns prevented many researchers from getting access to actual grid models and data. Also, with the advent of the smart grid around 2010, more researchers entered the field from other domains and were drawn toward the edges of the system and the distribution system where there were fewer issues comparable to the complexity and opaqueness of transmission operations (this is not meant to detract at all from fine and necessary work being done on the grid edge; that work is simply outside the scope of this paper).

It is also helpful to understand current academic conditions. The oft-repeated mantra "publish or perish" is more true than ever although more and more augmented with the perceived requirement to bring in large amounts of research funds. Right or wrong, metrics such as Google Scholar are widely used to assess, almost in real time, a researcher's perceived productivity. This is helping to drive a trend of researchers feeling the need to write large numbers of papers on topics for which publication is more likely. Our experience in the area of transmission operations is that the papers most likely to be published are based on sometimes extreme simplifications of the transmission grid so that results can be readily specified mathematically and then demonstrated on small, often unrealistically simplistic, grid models. This is partially because industry practitioners have little interest in reviewing papers that they view as having minimal practical relevance, leaving a pool of reviewers with limited actual industry experience. It is interesting to note that the full AC power system results provided by Tinney and Hart in 1967 using an IBM 7040 computer with 32 kilobytes of memory on a power system with up to 949 buses [52] are larger than many of the results given by researchers today! However, we recognize that there are exceptions, papers that focus on grids as large and/or complex as those that are operating today. Also, we recognize that much important insight can be gained from studying small and/or simplified systems. It is a question of balance, and we feel the balance is much too skewed away from the consideration of realistic grids.

Given the purpose of this white paper, some research suggestions that could be helpful in addressing this issue are, first, regarding opaqueness of transmission system information for research: as much as possible, DOE should promote the availability of historical data and models associated with actual electricity grid operations. As has been previously noted, there are legitimate reasons for restricting access to some information about grid real-time operations, and much of this information pertains to non-government entities. Nevertheless, a large number of historical data and models could be released. A specific example would be the information gathered during the August 14, 2003 blackout investigation. In light of how much the grid has changed since then (e.g., with the retirements of many generators and the construction of new ones), the CEII concerns applicable at the time of the investigation might no longer be relevant. Historical operational information with sufficient time lag, such as SCADA and PMU data, could be considered as well.

Second, there is a need for continued work on development of fictitious but realistic electricity grids and data sets. These synthetic electricity grids duplicate many of the characteristics of the actual electricity grid but do not raise CEII concerns and therefore can be freely shared and results of studies published. Development of large-scale, geographically sited, synthetic transmission grids for power-flow and dynamics models is presented in [53], for distribution circuits in [54] and combined transmission and distribution models in [55]. Further development of synthetic electric grids is also a recommendation in both [26] and [1]. During the past six years, there has been substantial work in this area, funding mostly by the Advanced Research Projects Agency–Energy. Current activities in this area include the Grid Optimization Competition, focused on the development of improved security-constrained optimal power-flow algorithms; and the PERFORM program, focused on better understanding grid optimization while taking into account asset and system risk. Both activities leverage synthetic grids. This work should continue, with the aim of increasing the realism of, and validating, synthetic grids in order to demonstrate their practical relevance. There should also be a focus on dynamics, especially associated with the larger amounts of renewable generation and storage being added to the actual grid. The representation of tightly coupled infrastructures, such as communications and cyber, should also be a focus. These results should continue to be publicly available without restrictions.

Third, there is a need for more standardization of electricity grid model and data formats to aid the exchange of information. Early on—in 1973—this was accomplished to some extent by the Institute of Electrical and Electronics Engineers (IEEE), for example the standardization of what was known as the IEEE common format for power-flow information [56]. This format was widely used, at least in the research community. Work on an enhancement was proposed in 1986 [57] but never moved forward in part because of the growing magnitude and complexity of electricity grid models. Around 2000, the Electric Power Research Institute developed the common information model [58], whose format has been extended to cover a variety of others, such as dynamic model information in [59]. Although the common information model is used in some applications, it is not widely used by the research community. Most power-flow and dynamics data are exchanged in vendor-specific formats that are not usually publicly disclosed (the Matpower Format [61] is an exception). Disclosure of the data formats used for exchanging information required by FERC was one of the recommendations of [26]. There are no widely used standard formats for the exchange of time-varying electricity grid data (the situation is even more complicated with distribution system information, but that is outside the scope of this paper). An attempt to specify a format that would meet the needs of the entire electricity grid community would be a significant, yet probably unsuccessful. Still, we think progress could be made in developing shared, public formats for the exchange of sufficiently complex models and data sets to be of benefit to electricity grid research.

Fourth, researchers and students working in the electricity grid domain would ideally have access to commercial-grade software tools that can be used with the large synthetic grids mentioned above, so researchers can at least approximate the complexity of the actual grid (for purposes of this paper, the transmission system), and, when available to them, actual grid information. Access would not be needed for every research project, but we believe access for relevant projects could be beneficial for research to move forward because there seems to be a pervasive lack of understanding of actual grid complexity among some in the transmission grid operations research community. This lack of understanding calls for broad education, which can be accomplished in a number of ways. Several vendors currently provide free or low-cost software licenses to universities. However, the lowest-cost licenses are usually restrictive either in terms of the sizes of the systems they can simulate or the number of users. An example of the impact on education of site licenses providing access to all students is presented in [60]. There is also a need for encouraging more broad access to commercial tools, which could result from encouraging their application on research projects. This is not necessarily a recommendation for the development of open-source software. Some open-source software, such as MATPOWER [61], is available for transmission analysis, but often open-source packages lack the ability to handle many of the complexities encountered in actual transmission operations.

11. Recommendations

During their 140 years of existence, interconnected electricity grids have been, and continue to be, technological marvels, and our society depends now more than ever on a reliable supply of electricity. Throughout their history, electricity grids have been in a continual state of change. We believe this will continue and perhaps accelerate as we integrate large amounts of renewable generation and as electricity usage changes in response to electrification of transportation. The future could be quite bright, but this unprecedented societal dependence on electricity comes with great risk. It is hard to overstate the societal cost of large-scale grid failure, particularly if coupled with some other calamity. Innovation is needed to make the grid more resilient. In this section, we present specific recommendations for research to help spur this innovation. We recognize that the future is inherently uncertain, so there is a need for broad research to (as noted in Section 3) future-proof the grid so that, regardless of how it evolves, the United States is prepared.

The specific recommendations that follow are grouped according to the sections of this report in which the relevant topic is discussed.

11.1 Section 4: Technologies for Support of Real-Time Operations

- **Data management.** The control center obtains real-time data from various sources (SCADA, PMUs, neighboring systems, non-electrical domains such as weather). Research is needed on managing these data efficiently for various applications.
- **User Interface.** Although the user interface for SCADA data has been developed over several decades, research is needed in the best way to display other data (or the information inherent in the data), such as phasor measurements.
- **Intelligent applications.** The number of protection and control devices is proliferating on the grid, but the operator only sees the effects of the actions of these devices. Research is needed on intelligent applications that can inform the operator which controls have taken what action.
- **User interfaces for abnormal conditions.** Although the user interface works very well under normal circumstances, improved interfaces are needed for alert, emergency, *in extremis*, and restorative conditions of the grid.
- **Transmission-distribution data exchange.** A major issue is increasing activity on the distribution system. Research is needed to determine what data need to be exchanged between transmission and distribution operators.

11.2 Section 5: Technologies for Engineering Tools to Support Real-Time Operations

- **State estimator.** Research is needed to replace the traditional, slow state estimator with the PMU-only linear state estimator as the backbone of the EMS.
- **Contingency analysis.** Research is needed to run contingency analysis at much faster rates based on the linear state estimator.

- **Dynamic contingency analysis.** Research is needed to make dynamic contingency analysis more robust and useful as the stability of the evolving grid is expected to get more problematic because of decreasing inertia and increasing instances of sustained oscillations.
- **Operator/optimal power flow**. These existing power-flow functions are seldom used because they require too much manipulation by the operator. Research is needed to make these functions more automatic.
- **Corrective/preventive actions.** If SE and RTCA detect problems on the power system, the operator is expected to take action based on experience. Research is needed to automatically calculate the best corrective or preventive actions.
- **Automatic corrective/preventive actions**. Once confidence is built in an application that can calculate the best control actions, the actions can be automatically taken by the computer. This is particularly important when the control is time dependent, for example in damping oscillations.

11.3 Section 6: Technologies to Enhance the Use of Historical Real-Time Data

- **Forecasting.** Research is needed on forecasting load and generation, recognizing that renewable generation depends on weather. Forecasting is complicated by the fact that separate measurements are not always made for roof-top solar or residential storage systems.
- **Machine learning.** Research is needed to develop the knowledge required for operators to take action. Deep learning from long periods of historical data can predict what actions are needed in certain circumstances
- **Model tuning.** Historical data can be used to update the model parameters for equipment in the system, especially for aggregated models. Research is needed on parameter estimation for various equipment.

11.4 Section 7: Technologies for Engineering Tools to Support Transmission Planning

- **Long-term forecasting.** Long-term forecasts are difficult because of generation deregulation and the rapid advances in technologies and policies. Research is needed into alternative methods for generating future scenarios.
- **Stochastic methods for planning.** Research is needed on probabilistic methods for the planning process. Although analytical methods are difficult, Monte Carlo-based methods can be developed using high-performance computers.
- **Grid dynamic behavior.** Research is needed on improved simulation of dynamic performance given the rapid development of generation and interfacing technologies as well as control and communication technologies.
- **Machine learning.** Data collected at the control center and substations can be used to develop improved models and simulations and therefore improved planning outcomes. Research is needed to develop these methods.
- **Planning coordination.** Research is needed into detailed standardization of planning methods so that power companies within the same interconnection can coordinate their planning.

- **Improved situational awareness.** Engineering studies are becoming increasingly complex, and research is needed to ensure that the engineers doing the studies truly know what is happening on the system.

11.5 Section 8: Training Simulators

- **Power system module.** The current OTSs are mainly based on power-flow simulations and do not fully simulate the electromechanical dynamics of the power system. Although electromechanical simulation is well understood, research is needed to fully integrate it into the OTSs so that PMU data can be produced in addition to SCADA data, and to support other operator functions affected by power system dynamics
- **Control center module.** Although larger utilities and ISO/RTOs have high-fidelity duplicates of their control centers integrated in their OTSs, many of the smaller entities use generic display consoles or drastically minimized versions of their control rooms. This does not provide adequate training. If cost is a barrier to having higher-quality control center representations in OTSs, then the industry should form consortia of smaller utilities to share OTS facilities.
- **Instruction module.** The current OTSs have very rudimentary instruction modules. Although OTSs are capable of importing snapshots of the actual system from the EMS to train operators using real scenarios, OTSs lack the capability to build scenarios for specific training goals (as is done in flight and nuclear plant simulators). Research is needed to develop automatic scenario-building for various training objectives, to develop trainee monitoring for evaluating training effectiveness, and to obtain automatic trainee feedback.
- **Power system simulation access.** Many groups of people working in the power industry (beyond operators) would benefit from improved simulator access.

11.6 Section 9: High-Impact, Low-Frequency Events; Restoration; Coupling with Other Infrastructure

- **Mitigating HILF event impact**. A broad portfolio of research is needed to understand, simulate and develop mitigation strategies for HILF events. This research needs to be the highest priority! Recent events have demonstrated that such events could be devastating to our country.
- **HILF simulation.** Currently there is a lack of HILF event simulations. Many people working in the electric power industry (not just operators) could benefit from participating in HILF event simulations.

11.7 Section 10: Research Infrastructure

- **Effectiveness of research.** A process is needed to assess and quantify the effectiveness of research on transmission grid operations.
- **Models and data exchange.** Research is needed to develop sufficiently complex, public electricity grid models and data sets using fully public data exchange formats.

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